COMMITTEE HEARING

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	Docket Nos.
Informational Proceeding and Preparation of the 2004 Integrated Energy Policy Report Update Interconnection Rules (2004 Energy Report Update)	03-IEP-01 04-DIST-GEN-1

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

FRIDAY, DECEMBER 10, 2004

9:12 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

ADVISORS PRESENT

Melissa Jones

Darcy Houck

STAFF and CONTRACTORS PRESENT

Scott Tomashefsky

Chuck Whitaker
Behnke, Erdman and Whitaker Engineering

ALSO PRESENT

Pat Aldridge
Southern California Edison Company

Stacy W. Walter
Pacific Gas and Electric Company

Robert A. Panora
Tecogen, Inc.

Kevin D. Best
RealEnergy

Kim Whitsel
Pacific Gas and Electric Company

Gerome G. Torribio
Southern California Edison Company

Dylan Savidge
Pacific Gas and Electric Company

Michael Iammarino
San Diego Gas and Electric Company
Sempra Energy

ALSO PRESENT

Tom Blair
City of San Diego

Nora E. Sheriff
Alcantar & Kahl, LLP

Daniel E. Tunnicliff
Southern California Edison Company

James A. Ross
Regulatory & Cogeneration Services, Inc.

Mark A. Moser
RCM Digesters, Inc.

Edan Prabhu
Reflective Energies

Robert Patrick
Valley Air Solutions, LLC

I N D E X

P R O C E E D I N G S

9:12 a.m.

PRESIDING MEMBER GEESMAN: We've got a tight schedule. I think we'll be able to get back on it by Commissioner Boyd and I compressing our welcome and introduction periods.

Welcome. This is a meeting of the Commission's Integrated Energy Policy Report Committee. I'm John Geesman, the Committee's Presiding Member. To my left is Commissioner Jim Boyd, the Associate Member.

To his left, Darcy Houck, his staff Advisor. To my right, Melissa Jones, my staff Advisor.

Commissioner Boyd, did you have anything to share with us?

COMMISSIONER BOYD: Well, only to say I'm impressed with all the work that has been done on this subject by quite a group of people over a long period of time. It's a very impressive piece of work that we've been provided as background for today's hearing.

I note the group has left a few knotty, I almost said nasty, knotty issues on the table for review and consideration. And I hope as a result of today's dialogue that we all collectively can see our way clear to some easy answers to those questions.

This is a very well structured workshop today, and I look forward to it. And it's going to be fairly lengthy, I believe, so I'll cut my remarks reasonably short. Thank you.

PRESIDING MEMBER GEESMAN: I guess the one thing that I would add to that is that because of the limitations of time and the very thorough written materials that have been submitted, I'd remind everybody that speaks today the highest priority is probably to educate Commissioner Boyd and myself.

So, please be careful about repetition. This is not a litigative forum. We've interested in information. We're interested in information that will help Commissioner Boyd and myself come to some conclusions on this subject. So try to structure your remarks with that in mind.

Scott.

MR. TOMASHEFSKY: Thank you, Commissioner Geesman. Good morning to everybody here. Glad the fog was not so much of an issue, at least for getting into Sacramento.

We will try to get done. Our expectation is to be done by 3:00, so just put that into your travel plans. But that always has a chance of changing at a moment's notice.

In terms of the agenda, what we're going to do is I'm going to give a quick overview of the working group report that the Rule 21 group put together, which was released on November 10th. And then we will have a discussion of, as we've called our five issues that we've been addressing, in that report. Namely the desire to develop network system interconnection rules. And then revisiting the dispute resolution process; the review fees; and net get output metering, which is contained in the rule. And then dealing with net metering and systems that have both a net metered and a non-net metered element, which is really an emerging issue that will become much more prevalent with the expansion of the net metering programs.

So that's our plan. The first discussion that we have after the overview will be more of a lecture by Mr. Whitaker with respect to interconnection rules, because the group really didn't have any issues of contention in that area.

So it's more of an overview of what is being done and some guidance as to really an affirmation from the Committee, and eventually the Commission, to explore those rules.

The other four areas are a little bit more contentious and we will have, in essence, a panel discussion set up for each of those with anyone sitting on the panel either having an opportunity to state their positions and/or just respond to other parties.

As far as administrative stuff, just a reminder that this hearing is being webcasted and also, since we do have a court reporter here, if you're not sitting at the panel in front of a microphone and if you need to make some comments, you probably want to come up to the podium so that we make sure that we have a full record and an accurate record.

Also, each of these documents and the presentations are now posted on the website, so if anyone's listening on the web, you can go ahead and download these things; or you can watch it through the webcast, audiocast, which I believe actually shows this stuff in real time, which is pretty good.

With that in mind, I'll go ahead and start. We do have a break built in and a lunch break. We'll deal with the net gen output metering section after lunch, which will be probably our most contentious discussion.

Just general background for those of you who haven't sat through 63 working group meetings, the Rule 21 working group was created about 1999. And in essence it's objective was really to respond to a couple of proceedings that were ongoing here at the Commission and also the PUC to deal with the standardized interconnection rules.

The rule, itself, was seven pages and we simplified it into a 55-page document. In doing so, now there's much more prescriptive rules and requirements. The idea is that there's a better expectation of what would be expected when someone wants to go through the interconnection process.

COMMISSIONER BOYD: Is there any way you can dim down the lights?

MR. TOMASHEFSKY: Oh, I'm sorry, absolutely.

COMMISSIONER BOYD: I think people on that side of the room might have a little trouble there. Thanks.

MR. TOMASHEFSKY: I have many choices, see if that works. Thank you.

We have about 200 people on the distribution list and we have monthly meetings. And, again, the perpetualness of the working group has really been designed to deal with rule refinements and addressing issues as they come up.

Since the rule was adopted in late 2000 and put into play on January 9th, I think, 2001, we've got a total of about roughly 450 megawatts of rule 21 related interconnections that have been approved by each of the investor-owned utilities.

You see the spike in 2002 is somewhat in response to the desire to get additional generation in 2001 by the time we get through the learning curve and get a lot of these, the process for interconnecting a little bit more efficient, a lot of the projects came online in 2002.

There's another 180 megawatts that are pending review. This does not include the 11,000 net metered applications and the process that we've provided, buy-down payments, and it does not include another 23 or 24 megawatts of net metered projects under the expanded -- program since that's been in effect for several years.

So there's probably another 400 projects on top of the 11,000, but that's not part of this.

The report, itself, is really a genesis of a desire by the working group to deal with some additional policy issues that were really not fully resolved during the 1999 proceedings.

So the white paper was issued. It was distributed to this agency, and also to the Public Utilities Commission, more on an informal basis. And as part of that process the PUC's rulemaking, which was initiated in March, then included the working group whitepaper as an appendix to the report. And, in essence, just responded back that there were some issues that needed to be addressed, and the desire was to have the Energy Commission investigate the interconnection issues, similar to what we did in 1999.

So in April we went ahead and initiated our own rulemaking. And as part of the scoping order in August, the working group was directed to put together the report that was posted and is the subject of today's review.

In developing the report we had four working group meetings in September and October. The final report was published on November 10th.

The folks you see on the list of contributors to the report have really spent a lot of time developing the text of the various sections, with the exception, the only one that's not included in that list is Chuck Whitaker, who we have under contract so we decided not to put him on the list. But he's had a very important contribution to that, as well.

So we're very appreciative of all these folks and a bunch of other people that are not on that list that have participated, sent emails and just have put their input into this process.

During the formal comment period, which ended November 30th, we received five sets. One from PG&E, Edison, EPUC, Cogen Council, City of San Diego and RCM Digesters. All of these documents are posted on the website and downloadable for your viewing pleasure if you haven't looked at them already.

So, as I said, and again in the scoping order, these are the five issues that we addressed. And that'll be the subject of the rest of today's discussion.

What I'm going to do here is I'm going to give you the 30-second summary of recommendations and then I'm not going to say too much more beyond what's contained in these particular slides.

The direction, itself. Each of these slides really asks for some general guidance and there's much more detail that we'll talk about, but with respect to network interconnection rules there's a desire to do that. And a desire to get some direction from the Committee and Commission to develop those rules.

And as Chuck will probably talk about in his discussion, we are looking very closely at the Massachusetts process which is currently doing something similar. And IEEE to develop a standard on network rules is roughly three to five years away. So, again, as we did before with the development of rule 21, we did not want to wait for IEEE to complete its work, but we said we would revisit it after it was done.

Dispute process. Interesting concept. We have a wide range of opinions on this issue with respect to "there's nothing wrong with the current process" to "there's quite a bit wrong with the process."

We've had some general discussion about

the idea of tweaking some of the issues dealing with timelines and things. And I think just also shaping some of the expected rationale behind various decisions that the utilities are making in coming to a final determination on a dispute.

Interconnection fees. We've dealt with an $800 and $1400 initial supplemental review cost as part of the rule. When we adopted that four years ago we said we'd revisit it. We have had a couple of PUC directives to look at various costs. It is also a subject of the cost/benefit testimony that was filed in phase one at the PUC.

So there's some areas that we need to focus on with respect to how the fees are set up, as opposed to the specific costs of the fees. So there's some gray area of determination here about where our work ends and the PUC's work begins. But we'll work through that process as we come to a final resolution.

Net metering for projects with combined technologies. In essence, the fact that I have a house on here is probably not the appropriate thing to have on there. But what we have now is we have situations where you can go ahead and put a net meter project for up to 1 megawatt, PV and wind and fuel cells and biogas on a pilot basis.

And a lot of this is being supplemented with existing non-net metered projects. And it's created some issues with respect to the revenue consideration of net metered projects.

And what you'll see as a common theme through a lot of this is that many of the technical issues surrounding interconnection are really not of issue here. It's really the tariff-related and fee and cost-structure issues that have become more of the nuance of the problem that has further implications.

And in net gen output metering, this really comes down to whether or not a meter is actually required; whether estimation is appropriate or not; whether the quality of the data is of a standard that is good enough for billing purposes. And we'll get a lot of discussion on that in the afternoon.

This issue we have been debating for about two years now. And the last two months in documenting it we at least have a little bit more clarity on where we want to go. But there's a lot of guidance that's needed in this particular area.

So that's the nutshell. In terms of next steps, I guess the week of January 6th -- January 6th is on a Thursday, so it's the first week of January -- what we would expect to see at the end of this particular process.

After this hearing is done the Committee will put together its recommendation and release that hopefully during the first week of January. Provide two weeks for public comment on the Committee recommendation. And on that schedule would have the full Commission consider the recommendation on February 2nd at our business meeting.

Once that happens, if you're familiar with what we did in the '99 proceedings, we would send the final recommendation over to the PUC, who would then convert that into a proposed decision. And reach a final decision and that would be the basis for doing some of this additional work.

The important thing to note on that conversion into a proposed decision is that the intent is not to have the issues relitigated at the PUC, but merely to focus on factual inaccuracies and some other things related to that. So it's not here to develop the record that we have put together here.

So, that's my opening comments. What I'm going to do is I'm going to turn this over to Chuck and he's going to talk about system interconnection rules. And when we're done with that we'll go into our first panel discussion.

PRESIDING MEMBER GEESMAN: Scott, before you do that, would you turn back to your slide number three?

MR. TOMASHEFSKY: Sure. Yes.

PRESIDING MEMBER GEESMAN: It looks to me that if you take out 2002, a normal year sees, I don't know, somewhere between 60 and 80 megawatts of capacity brought online?

MR. TOMASHEFSKY: Yeah.

PRESIDING MEMBER GEESMAN: So if I look at the 180 megawatts of projects pending review and approval, is that a two- to three-year volume there in that queue?

MR. TOMASHEFSKY: That's a good question. Some of the projects that are pending in the queue are projects that have say out there and have not really moved much. And there's probably a variety of reasons for that. Some developers will decide they're not going to go forward with the project. Some areas in the review process, at least as far as dealing with the contractual work, has just taken a long time.

A lot of that has become more efficient in terms of how it's being processed. But there's some projects that someone will file a project and then not do anything else. And it'll be awhile before we collectively take it off the books.

PRESIDING MEMBER GEESMAN: Is there an average period of time that a project stays in the queue?

MR. TOMASHEFSKY: That's probably a better question for each of the utilities.

PRESIDING MEMBER GEESMAN: Okay.

MR. TOMASHEFSKY: It really ranges from a very short time to quite a long time.

PRESIDING MEMBER GEESMAN: Okay. There's not any performance standard or limitation on how long a project stays in the queue?

MR. TOMASHEFSKY: We have put in a -- we actually are working on a revision to our application form where we're trying to address that particular issue, where after a certain amount of time we'll take it out of the queue. We haven't fully finished that discussion.

You should also note, though, that in 2002 there's a slight skewing of the data because there are two large projects that went through a Rule 21 application process which you would argue are probably not --

PRESIDING MEMBER GEESMAN: I see.

MR. TOMASHEFSKY: -- distribution level projects.

PRESIDING MEMBER GEESMAN: Okay.

MR. TOMASHEFSKY: So I think your characterization of 80 to 100 is probably good.

PRESIDING MEMBER GEESMAN: Thank you.

MR. TOMASHEFSKY: Sure. With that, I'll turn it over to Chuck.

MR. WHITAKER: Good morning, everyone. My name is Chuck Whitaker; I'm with BEW Engineering. And as Scott mentioned, we are part of a team that has been providing consulting services to the Rule 21 project since the early 1800s, I think when we first started this.

Scott asked me to talk to you a little bit about the direction we're going on network interconnections, which has been a secondary issue to the interconnection process, and I'll get into the whys of that. But it's an issue that we knew about when we did the first round, and we set aside and now has become a much more politically interesting topic. And so we've been asked to deal with it.

So, the first thing you have to understand, I get comments from one of our representatives that whenever we talk about networks he isn't sure whether he's supposed to plug his computer into it, or what we're talking about.

So I threw this up here. A network does not involve Cisco routers or internet protocol. It does not infer an opportunity for meeting prospective clients and employees, because this is the other sometimes confused networking issue that we are involved.

But it does involve a multi-source, high reliability electric service that is fairly narrowly scoped through a few utilities in the country, in specific locations, specific areas. And it provides an interesting situation, both technical situation for the interconnection process and for the providers an interesting clientele basis, I think.

So, the lecture part of my lecture here

will be to run through this real quickly. I think you all understand what a radial distribution system is. Power starts at the substation and flows out to the radial loads in a single direction.

The first type of network system that we'll talk about is a spot network which provides multi-source capabilities to -- I don't have a pointer with me -- to one or two customers, providing -- what we have here is a substation with multiple feeders, or a feeder with multiple taps providing a single customer with multiple sources of power.

And this reliability means that if something happens on this feeder, these two feeders can provide the load.

The first level of concern you have is well, what happens if I have a fault on this feeder. I don't want these two feeding back into that fault. So we have these devices here called network protectors which are basically reverse power relays which only let the power flow in this direction in each of these legs. As soon as you get a fault here and it tries to flow current or power in this direction, this network protector opens and isolates.

These devices tend to be very unique, very specific to networks. They can be temperamental. They can be quite old, in fact, because a lot of the network systems out there are exceedingly old. And so these become a very key source of discussion for this work for going forward.

The next level, and the least common, is the grid or area network which would be a downtown area like parts of Oakland, downtown San Francisco, Manhattan, where you actually have a grid of wires throughout the city that provide multiple sources, multiple paths for power to flow to a number of individual customers, a number of high-rise buildings, fed from multiple substations potentially.

And it's a very high reliability system. Again, I think the last time a grid network was built was 1977, so they tend to be fairly old and cantankerous. And so there's a lot of issues that are not understood and need to be better addressed. And if we are going to put generation in here, what happens with the current flow and how do we keep things from becoming less reliability by doing that.

PRESIDING MEMBER GEESMAN: You mentioned San Francisco and Oakland. Are there other areas of California that have grid networks?

MR. WHITAKER: Sacramento -- we don't have anybody from Sacramento here -- I think they have.

UNIDENTIFIED SPEAKER: Long Beach.

MR. WHITAKER: Long Beach, okay. I don't think San Diego and we weren't sure about L.A. We didn't have anyone from L.A. to tell us about that.

PRESIDING MEMBER GEESMAN: But L.A. would not be affected by Rule 21.

MR. WHITAKER: L.A. would not be affected by Rule 21. Although, clearly this is all groundbreaking work, and we're working in step with what IEEE is doing, with what Massachusetts is doing, with what other utilities are thinking and considering. And whatever we do will affect what goes on in L.A., no doubt.

PRESIDING MEMBER GEESMAN: Sure.

MR. WHITAKER: So we wrote -- our goal in the technical group was to say, okay, what are the steps we need to take to understand what the issues are related to network interconnection. How do we get to -- is there some level of simplified interconnection that we can allow on spot and area networks.

And so our part of the report is our plan to move forward and to understand that. To learn what we can do.

So in the report introduction we talk about network protectors and how they have unique technical requirements. That there have been issues when DG has been installed on networks in the past, because some of these issues weren't understood in the initial requirements.

That the utilities are each, right now, stuck with divining their own set of requirements and guidelines because we don't have this yet in a standardized way.

And right now in Rule 21, as soon as you get into the initial review process the first question is, is this a network application. If so, you go to supplementary review. And then, you know, all bets are off as to how simplified it will be. And they're establishing requirements on a case-by-case basis at this point.

This panel asked us to look into that

and try to come up with uniform rules and potentially simplified interconnection. And in doing that we need information. That was the key issue that was brought up by everyone, is we really need to understand what the issues are.

So in addition to our internal talent and knowledge base, we've been looking to outside sources. One is the Massachusetts DG Collaborative, meetings of which I've been attending the last month or so. And find to be very interesting and parallel Rule 21 in many ways.

They are addressing the same issue of networks. They have different people with different perspectives, and hopefully some good information will come out of that. I think it will. And they are very interested, as well, in what we are doing and how we're moving forward and what information we get. So they are very interested in this collaboration.

Secondly is the distributed utility integration test project, which is sponsored in part by the Energy Commission as well as the Department of Energy. And under their newer DOE contract one of their topics is to do it as a project where we're looking at testing a number of different distributed generation devices together to see their interactions on the utility grid.

And networking was suggested to be sort of the next topic after our first phase of testing to look into. So right now we are scheduling a meeting which will be, I think Susan said, January 16th, but don't write that down. Mid to late January will be a meeting that will involve -- it will probably be in New York -- involve those utilities, utilities from California, as well. To meet and discuss what the issues are, start to get a handle on that. The idea will be to understand what testing needs to be performed to answer the questions.

We had four objectives in the report. One is to get a handle on what all the issues were. What load levels cause problems. What fault types are of most import. And how do we deal with spot networks versus area networks.

We needed to develop some supplementary review information, and this would be the standardized approach to addressing the interconnection on network systems. We need to determine some general requirements. In Rule 21 we have a section of general requirements that distributed generation that wants to go on the utility system must do these things.

And then we go on to the initial review process and say is the application and the situation it's going into, does that allow simplified interconnection, or are there specific issues that need to be addressed. So we need to develop these general requirements first, and then decide how we can develop simplified screens.

Following that we have our task list, things that we need to do. One is just to come up with these basic definitions. Is it area, is it grid. What's really the difference. Seems mostly to be the number of customers on the system. So getting those kinds of basic definitions.

This is really an area where the knowledge base exists in very few people. Within any given utility there's two or three engineers who really know what's going on, what really happens in their network system. And we have to, you know, pull this information out of these folks so that we can all understand and make decisions on that.

We are going through and identifying

where the networks are, both spot and area, in California. And what the characteristics are. We want to find out who all the interested parties are nationwide who will be able to help us with the kinds of information we're looking for. Meaning utilities, DG suppliers, customers who may have an interest in DG, regulators and the equipment providers, particularly those two or three companies that make network protectors.

Next we need to identify other projects. Distributed generation is being installed at least on spot networks. Everyone's aware of that. There are rumors of a few systems going in on some area networks. And we'd like to know what has gone in, what they've done, what issues they've had, how they addressed their concerns.

And there's a number of different methods that we have for getting some of that information, DUIT, the Mass DG Collaborative. Other sources of information include the PG&E protocol that PG&E has put together. IEEE 1547 has a small amount of requirements in the main 1547 document, which is the one that was published last year regarding DG interconnection. There's a follow-on project, 5047.6 that is going to address specifically network interconnections and provide more detail. And that's going to start early next year.

And then get information from the manufacturers on what equipment they have, and what equipment they're contemplating. If DG and networks becomes an issue there will likely be new equipment made available to address that.

Go through and find out what other rules and requirements are out there. Identify existing DR on networks. What problems people have found and what solutions they have used from the utilities' and systems integrators' perspectives. And then look at the cost of dealing with these things.

And I guess that was the end of my presentation. So this is the basic outline of the report and how we plan on moving forward over the next year. So, if you have any questions I'd be happy to answer them.

PRESIDING MEMBER GEESMAN: You say over the next year, you've got a more specific timeframe than that in terms of when we'll actually see something in public?

MR. WHITAKER: Well, what did we say,

Scott? Yeah, I think to the extent of coming up with some basic requirements, I think it's probably within, yeah, within the next two -- by the end of 2005.

There's a lot of taking the first step. Everyone's watching everyone else and they're afraid to move forward. And we have a lot of that sort of reticence within our Committee, as well. No one wants to be the first one to find out, oh, gee, that was a mistake.

PRESIDING MEMBER GEESMAN: Sure.

MR. WHITAKER: Not on my network system is really the call of the day. So, it is going to be a slow and methodical process. And a lot of it will depend on what information we find and what other people are doing.

I will tell you in timeframes that 12 months is actually pretty quick to really come to thorough conclusions on things. 1547, I wouldn't expect to see a published standard out of them for at least three to five years. That's a typical process. And they're just starting that early this year.

And do it, that project where we'll be trying to develop a test facility, right now the plan is to begin development of that test facility in 2006. So the testing will come after that.

So, we will be -- in a year we will have, I think, a handle on what the issues are, maybe not full resolution on a lot of them, and methods to address some of them, but we'll have a plan to go forward. And I think we'll have enough documentation to allow certain levels of interconnection.

PRESIDING MEMBER GEESMAN: Thank you.

MR. TOMASHEFSKY: Thank you, Chuck. And let me add that what we will do is we can develop, we can put a lot of this into a report to have some further communication with the Committee and look for some approval on a direction that we're going.

So, there's a technical side of that; and then there's also an informational side of that. So we'll be providing that, as well.

Okay. Shifting over dispute process, what I want to do is we'll start a panel discussion. And if I can have -- what we'll do is we'll have folks sit around, it's not a round, it's not a square table, I guess it would be a "V" table. If I could have Pat Aldridge, can you go up to the table? And Kevin Best, Bob Panora and Stacy Walter. Is Mark Moser here? Haven't seen Mark Moser.

And what, I guess, we will do is since Edison's basic position in this has been that the current process for dealing with disputes in the PUC arena is perfectly fine, so I'm going to have Pat walk us through. Just give me a minute to make sure I find it again here. We've got some distributed as well, so -- here it is.

And keep in mind when you look at this document, and it actually is more simplistic than you think, but this is a very simplified process. So, with that in mind I'll turn it over to Pat.

Pat, do you want a pointer at all, or are you okay?

MS. ALDRIDGE: I think I don't need it. I'm not going to (inaudible) every single box on there. A lot of it (inaudible).

I want to give a little background. In approximately 1999, 2000, all of the California utilities that are under the jurisdiction of the Commission got together with the Consumer Services Division of the Energy Branch of the Commission and we sat down and looked at the complaint process, both the informal and formal complaint process, to make sure that we were utilizing everyone's time to the best advantage. And that the customers were then having the proper opportunity to be able to voice their complaints.

And so we met over a series of probably six to eight months and developed this process. And it basically breaks down into three groups.

The first set is when the customer initially contacts the Commission and says that they're, you know, dissatisfied with some sort of a bill or their service or some area such as that.

They have within ten days the Consumer Affairs Services Division of the Commission will have the customer record what their problem is. Will contact the utility; ask the utility to research the situation and get back to them. And advise them -- the CSD then advises the customer of the results of the investigation.

If, at that point, the customer still is not satisfied, then it goes into step two. And the consumer can request that they have a supervisory review.

What happens at that level is that an appointee that is above, at a high level in the

CSD, along with a manager at the utility and the consumer can sit down again in a face-to-face, if they'd like, over the telephone, whichever manner that the customer prefers, and delve into the situation in a greater detail.

If that doesn't resolve the situation then we can move into step three, which is the area that I think would probably be the area that would work the best for Rule 21.

If the customer is still not satisfied we can go into some sort of a, either have an area where you'd sit down and have a face-to-face; you could have some sort of mediation; you could have any other kind of informal or formal litigation that the customer wished to have.

And at that point, because Rule 21 is a very technical rule and there are a lot of issues that don't normally come up in regular complaints, it would provide the opportunity for experts to be brought in to assist in resolving the complaint.

The basis for all three of these steps basically is to try to resolve it at a level before it actually goes to a formal complaint before an ALJ and a formal decision is issued.

We have been using this, like I said,

since the year 2000. It works very well. We have reduced the number of formal complaints drastically that have actually gone into the ALJ division. And I think most customers have been very satisfied with the way that it's come out, because it gives us the opportunity to do some sort of, you know, give-and-take on the situation when we're following step three.

Edison's position all along has been that Rule 21 is a tariff just like the other tariffs are; and that we should try to resolve any complaints within the format that we follow for any other tariff that we might have a complaint on. And that's why we've brought this forward through the Rule 21 Committee and offered this rather in-depth chart there to kind of discuss with. Because we think that we do have an opportunity to use some sort of mediation or some sort of other resolution factor in the third step on this complaint process.

PRESIDING MEMBER GEESMAN: Do you currently make use of mediators, the current system?

MS. ALDRIDGE: It has been used. It isn't used a lot, I have to admit, because the majority of the complaints aren't to the depth that that would be required.

Edison has used it once. And I don't know if the other utilities have or not. And --

PRESIDING MEMBER GEESMAN: And in that instance was it a third party, a private mediator or --

MS. ALDRIDGE: Yeah, there was a --

PRESIDING MEMBER GEESMAN: Okay.

MS. ALDRIDGE: -- private mediator that was brought in. And when that happens then each party absorbed the cost, you know, the expense for having that mediator come in, in the Edison situation. And then there was a representative from the Commission that also was involved in it.

But I think that, you know, like I said, Rule 21 is a more technical, more in-depth rule that probably is going to have issues that are different than a billing complaint and that kind of thing. So, it does -- the format, I think, would work with that type of situation. We just have to have the technical advisors that we could bring in and use.

PRESIDING MEMBER GEESMAN: Okay, who's next?

MR. TOMASHEFSKY: Stacy Walter from PG&E.

MS. WALTER: Sure. I have just put together some bullet points that were posted to web yesterday.

Good morning, Commissioners and Staff. I'm Stacy Walter; I'm an attorney for PG&E. And basically PG&E supports the use of the existing Rule 21, section G, the dispute resolution process, as a starting point to tweak or make revisions to the rule.

You know, we support the idea of having the energy division involved if that's going to help move the process forward. And we also have suggested that it be, you know, the ability to have an independent mediator at the choice of the parties could also be added.

We've had experience with the Rule 21 dispute resolution process. We found that it is a useful tool for getting the parties together at the table talking, sharing information and working towards resolutions of some, you know, difficult issues.

One example of that that ties in nicely with the presentation we just had regarding the spot networks, you know, we've had a dispute with one of our customers about interconnecting on a spot network. And we were able to work through the issues. We were able to come to resolution. We were able to interconnect those projects.

So, even while you see that it's in the infancy here, you know, the dispute resolution process in a situation like that, you know, worked for us to accomplish what our goal is, which is to work together with our customers to find ways to interconnect them and be consistent with providing safe and reliable utility service to all our customers. So, in that situation, you know, we've been pretty successful.

As Pat has said, you know, the dispute resolution doesn't get used that often. We prefer to try and, you know, work out issues with folks as they come up and try to find solutions. You know, sometimes it's just not possible and you do need a mechanism to resolve a dispute.

And, you know, PG&E, once we've worked, and it's taken, you know, a lot of time and effort on our part and also on the part of the DG provider and the customer, we've tried to take another step forward. And you can see a result of some of that work coming out of the dispute that we had on the spot network. We've put together materials about how some of those interconnections might be accomplished to help move that process forward here in California and elsewhere.

Another example of that is in areas where we, you know, maybe had a contentious issue involving measures that are needed to interconnect safely and we've met and revised our positions. We even incorporated them into a, you know, PG&E whitepaper so that then they could be used in future projects where it's applicable, if the same situations come up.

And that's an effort that we try very hard to make sure that we can work to interconnect projects as they come forward. And we've interconnected quite a few. I think it's something like 6000 different DG projects are interconnected in PG&E's service territory.

And then the only other issue I'll just mention briefly, because I think most of the working group agrees with us, that they did take a look at the Massachusetts dispute resolution; it has a slightly different provision. And we prepared a comparison between the two.

And like the other members of the working group, you know, we think that the dispute resolution process that we have in place, with some tweakings like adding a mediator, is the way to go. We're supporting the recommendations that the CEC Staff has put together in the report before you today.

PRESIDING MEMBER GEESMAN: What precedential value should any particular successful dispute resolution have?

MS. WALTER: Well, you have to be careful, you know. And I'm a lawyer, not a technical person. But the one truth that I understand with all DGs, it's all about your location. Location, location, location.

So you can take the same generator and you can put it on like a spot network, you can put it on an unloaded line segment and you're going to have different requirements, depending on where it is.

But to the extent that you have a similar situation, then, yes, we do, you know, there is some precedential piece. But, like I said, have to put some flashing lights on that because it doesn't always translate exactly.

PRESIDING MEMBER GEESMAN: I can appreciate that. I guess the question I have from a process standpoint is how can we build into the process some type of assurance that where there is value or potential to learn from earlier disputes, we avoid reinventing the wheel in each dispute and attach some learning curve to those earlier dispute resolutions.

MS. WALTER: Well, in most situations I think that the Rule 21 working group process that you've established is very helpful because, you know, it provides a forum. You know, the disputes that we have had, they get discussed, they get vetted, you know, in terms of not a dispute that really relates just to one customer, but when they have broader applicability, you know, that's part of the process that goes on with the working group, with preparing reports like this, with bringing it, not just utilities but also members of the DG community and customer groups.

I mean that's really, it's not like you can sort of set it in time. It really is -- there's new technology all the time, there's new situations that come up. What we try to do, you know, is come up with ways that we can successfully interconnect to them.

PRESIDING MEMBER GEESMAN: At your company how many disputes per year are we talking about?

MS. WALTER: Well, I think in terms of using the formal Rule 21 dispute I think we've had one. We've had one informal. But there are issues that come up, you know, frequently. And I would have, you know, I'm not sure that we, you know, track.

PRESIDING MEMBER GEESMAN: Right.

MS. WALTER: Sometimes they're just misunderstandings. And, you know, communication is an important piece; it's something that we're looking at, as a company, on how to better communicate with DG customers. We sponsor, you know, PG&E has workshops where we try and make sure folks understand what our requirements are.

Our experience is that if the DG community and vendors know what we require in advance, it makes for a much smoother process. And there's a lot, you know, there's always going to be something that comes up that hasn't been seen before, or, you know, a wrinkle when you're dealing with something like this.

But we try and use, you know, communication, participation in the working group, providing comments on, you know, useful reports like this one to try and, you know, keep the process moving so that we can support DG interconnections.

PRESIDING MEMBER GEESMAN: Yeah, I have to say these dairy guys, and I hope some of them are here today, seem to have a fairly strongly differing point of view as it relates to PG&E. And that, as I think everybody can probably understand, creates quite a bit of consternation within state government.

MS. WALTER: And, you know, we actually are working for this spring we want to put together a dairy oriented type of workshop experience. The EBio tariff is a relatively new one. There have only been a handful of dairies interconnected under that program so far. You know, not all dairies are taking advantage of the net metering program.

There's some issues about the way the program's set up, you know, the statute that created it provides a certain formula for credits. There's some concern about dairymen about that, but that's the thing that was established by the Legislature.

It's handled a little bit differently than a PV or wind, smaller wind net metering. So there's a little bit of a learning curve in terms of metering and things like that. But, you know, we want to do better, and the way that we think we can accomplish that goal is by having a workshop, bringing the parties together and talking about what we require in order to provide, like I said, safe and reliable utility service.

PRESIDING MEMBER GEESMAN: Okay. Thank you.

MR. TOMASHEFSKY: We'll shift perspectives here from utility perspectives to customer perspectives. Start off with Bob Panora who works for Tecogen. And he'll explain some of the materials you have actually included in the report. And then we'll follow that up with Kevin Best from Real Energy.

Bob.

MR. PANORA: Here we go.

MR. TOMASHEFSKY: Just tell me when to hit the slides.

MR. PANORA: Okay. Good morning. I

want to tell the story of the Tecogen/PG&E dispute that took place in really 2003 mostly. And I want to start by saying I think it's a very very important case study because it really hits right smack in the center of what Rule 21 is all about. It's all about simplifying the interconnection process.

And this whole dispute was not something that was obscure on the margins of the technology of what we're trying to do. It's right down the center of what Rule 21 was all about. So just some background, I'll start with that.

The scope of the dispute was 24 units, 15 projects. So, it very easily could have been 15 disputes if it was done separately. But it was 15 different places.

The product was the Tecogen cogeneration module that has been around since 1983. And when Rule 21 came out, we were very very excited to see that there was this really groundbreaking type testing certification aspect to it. I think that was just, it was just from manufacturer's point of view, it was wonderful to see that put in black and white. That if you got your machine certified by UL to Rule 21 standards, and the site was specifically screened to be okay to be simplified, then you could, indeed, go through a simplifying interconnection process.

So the questions about some generators are one way on one site versus another site, well, these sites were all screened in the Rule 21 process.

So, in any case, we had all these 15 projects with interconnect applications made out. The sites all passed the screens. The machine was Rule 21 certified by UL, spent a lot of money doing that. Fully certified. Passed all the screenings.

And so technically these machines qualified per Rule 21, these are the words of Rule 21, simplified interconnection without additional requirements. So, in our mind a pretty cut and dry situation.

The next slide, Scott. So, what happened in the -- the machines should have gone through the simplified process, but they were bounced out to supplemental review. And when that happened PG&E ruled that we required a completely redundant safety system, completely redundant to what we had in our machine.

The problem was not only was it redundant, but it was very very expensive. It followed their internal design criteria which really matched how they would treat, you know, a substation design situation.

And just to give you an idea, the machines, at times they're the size of a desk. They're 75 kilowatts; they're not massive power plants, they're 75 kilowatts. Essentially projects were all stopped. The units were stranded in our factory, in the field. And it was financially, you know, devastating for all parties involved, the developers, you know, the schools, the hospitals, the nursing homes that wanted to get the machines in. And, of course, our factory was, you know, was in trouble.

We looked at the dispute process that's in the system and decided that it just wouldn't be quick enough. It was unfamiliar to us. We don't understand how those things work, as a manufacturer. Just not a venue that we're used to dealing with. And we were very afraid that if we went through that process would it be precedent setting. There was nothing that said that if we did each facility one at a time, you know, it would pass on to the next facility. So it was worrisome from that point of view.

What we did was we wrote, you know, an impassioned letter to the board of directors of PG&E. And that triggered action where we got around a table and obviously we came to a solution, otherwise I wouldn't be here today.

And the solution was a less expensive redundant relay. Not a great solution, but it allowed the projects to proceed.

Now, all the units, you know, they're most of them up and running. The sites went on, and we're working with that guideline that PG&E established in our negotiation. But there are unsettling aspects of the whole process that I think I just want to mention here today.

The great innovation of Rule 21, in my opinion, is that it establishes a standard framework that developers can say if the machine's certified, if the site meets the 11 screenings, then you can predict what the process is going to be to get interconnected. It's predictable and it's simplified.

And so that great innovation here has been undermined. I mean who would get certified to Rule 21 after what happened? You'd be crazy to. I mean, you know, our competitors have mentioned this to me that they had thought about going down that path, but given what happened to Tecogen, it didn't make any difference.

Before Rule 21 we had to put a redundant set of relays in when we were uncertified. Then we were certified, it's the same thing. What was the point of it? It cost, you know, well over $100,000 for that process of having UL do all that testing.

The other thing we've learned is I think existing dispute resolution process is inadequate. It's too slow for what was happening with these machines piling up in the factory and in the field. It wouldn't get to the finish line quick enough.

It's also, again it's very unfamiliar territory for people like us who don't work in this venue. And, in fact, it may be inappropriate place to discuss what always seems to settle out to technical discussion. You know, electrical engineers talking jargon back and forth, and it gets very difficult to settle something like that, I think, unless there's a means for doing that.

And I think we did feel that if we went down the dispute resolution process and where it was, we didn't feel we had a certainty that after all the time and trouble that it would necessarily be precedent setting. And that was troubling.

End of the day we have a settlement. It works for us. But it's not permanent, necessarily. It's a tenuous settlement. And it is expensive. It's not like the relay is free. It's, you know, a $5000 or $10,000 proposition each time you put a machine in. And so it's not totally satisfactory.

So in regard to the dispute resolution changes and so forth, we'll let Kevin talk more about the specifics of what we think should be done, so I won't be redundant to what he's saying. But I want to, you know, repeat here. The process needs to be timely; it needs to be predictable in the sense of has a timeline that's defined. The outcome, of course, can't be predictable, but the steps should be somewhat predictable.

And it needs to have the ability to resolve these technical issues that aren't, you know, most laymen, their eyes just glaze over when this discussion begins down that avenue. So it needs to have that kind of expertise available.

And I think its applicability to similar projects, it's so self evident to me that it should have that characteristic if it's talking about certified equipment in sites that qualify for a simplified interconnection, it should have that type of precedent setting ability.

So that concludes my little story here.

MR. TOMASHEFSKY: Kevin.

MR. BEST: Good morning. Well, thank you for hearing us on this topic. I'm Kevin Best with Real Energy. This is the second time I've been before some of you Commissioners this week. We were at the California Energy Action Plan at CPUC. So, some of these thoughts will be repeated.

I'm the Chief Executive of Real Energy. We have a little over 30 plants interconnected in the State of California in UDC service territories, we're in all three. We have several technologies we've interconnected, photovoltaics, microturbines, internal combustion engines.

We have a very kind of high profile customer base including CalPERS, CB Richard Ellis, Arden Real Estate and the State of California is one of our largest clients. We power the Public Utilities Commission building; they switched many years ago.

We are installing all efficient, very efficient systems recycling energy on all the fossil fired plants, and of course the balance are renewable. Commissioner Geesman, you're looking at number of 50 to 100 megawatts a year installed as kind of a normal year. I don't think there's anything normal yet about this industry.

We, as a company, signed with customers all class A office buildings, almost without exception, over 50 megawatts last year. We're one company. So, as soon as we have a little bit of certainty in this sector, Wall Street's dying to play in this arena. And the money is endless for conservative investments in energy with little merchant plants in buildings. And we're very hopeful that we'll be talking about 500 megawatt years and 1000 megawatt years sooner rather than later.

I'll say that our experience with the people in this room from PG&E has been extraordinary. They're hard workers. I look around the room, I know them very well. And from an individual point of view, with the exception of one or two individuals, very honorable group. We've been pleased to work with them.

Now, we entered a period of time in San Francisco where lots of customers wanted DG. We have DG in the roof, in the basements, in the parking garages. We're all over that town. We could do a whole lot more and we've stopped it cold.

We are probably most taken aback by the nature of uncertainty that occurs mid investment. We were $5 million into some $7 million worth of construction projects when we learned we had a problem. This is not the time to learn you have a problem.

The problem was pretty simple from the utility point of view. We simply needed to import power into the building virtually all the time. And there were mechanics, and you go through the math, but it basically said we could run about 100 hours a year. Well, that doesn't work from an economic investment point of view.

And so we were quite nervous. And we pulled all the stops to learn how we got here. And I came in about four months into the process and spent four or five months in it, myself, understanding specifically where we were.

And the fact is we had proposed a technical connection methodology that seemed reasonable to us; and the utility said no. We said why. And that dialogue, after four or five months, never came to conclusion. We never knew why.

And, of course, after that period of time you start asking if there's the ability to process the answer. We learned very quickly, by bringing in third parties, and this was one of our recommendations is there always be a third party in the room just to keep everyone sober.

We learned that there was probably the inability to answer why. It was just nervousness on the part of the utility, rightfully so, to protect their customers. And they weren't going to let one customer jeopardize the rest.

By the way, as a background, there's no incentive for PG&E to be at this table with us. We're very difficult, you know, to work with; they don't think about power this way. Again, I'll pitch that we need incentives for the utilities to do this. Why are they even coming to the table.

It's amazing to me. They'll have 15, 20 people in the room to help we, as a customer, think about this. When the answer is we just need them to respond, why can't we do it the way we propose. All these people probably don't have the answer.

So, we were shocked as we ran up the organization chart at PG&E that PG&E finally hired a person from the east who eats and sleeps and writes books about networks. And flew that person out on their nickel; that was kind of a shock to several people in the room here, that PG&E would do that.

And I think it was 90 minutes into the meeting that the fellow said, well, why won't you just do it the way they're recommending. Now, we eventually, you know, realized that was a watershed. And having EPRI at the table to kind of just witness what we were going through, and they never charged us, it was just great having EPRI come, sit and listen.

That was the breakthrough. We had a fellow who knew what he was talking about. And the interconnection that we were proposing was just fine.

And so we proceeded then to document

that technical agreement. That took another two months. These were weekly meetings. And I've got to say, for a little company like Real Energy, to be taking this amount of time with this amount of investment at bay, with customers that had signed up with us and we were working on their buildings, and other customers that heard all of the drama around. You know, this provides lots of uncertainty for customers and the investment community.

But knowing that the minute we entered formal dispute resolution we couldn't speak to the PUC Commissioners. We had this ongoing effort of educating them in the period of time that we could speak to them on the topic.

And so this is a lot of people, a lot of attorneys, a lot of our time. We're just a small company here. And so in the seat of it was uncertainty on the part of the utility about what would work and what wouldn't. So, that was the beginning, to find that they just didn't know; and were able to get the people in the room that did know. And then we could come to conclusion.

Well, the end of the story is that we took a very conservative position on just how much power we should import all the time. Under Rule 21, under radial feed, it's 5 percent of the generator. Well, we were factor 6, factor 7 of that. We were negotiating some smaller number. And we, Real Energy, agreed let's leave it conservative, but then let's agree on a method for monitoring in real time, getting the parties together post-agreement on a regular basis, and lowering that number until we realized from the technical information we had, that hey, folks, we're getting too skinny. This is the place that's right. And if it's factor 2 Rule 21, or factor 3 Rule 21, we'll settle in there.

Now, obviously PG&E wants to be very conservative. And, of course, we're aligned to be less conservative.

I saw on the board this morning, you know, that we have input to discuss this from Massachusetts. And we have input from DUIT. Well, neither of those parties have done anything like this. Real Energy installed our first network system in Oakland in 2001. Several engines, multiple meters.

Our second was in Long Beach. And our third, fourth and fifth were in San Francisco. We have over ten years of experience now, ten-year equivalent on a meter, because we have multiple meters several years. And we have a lot of information.

Now, it's very convenient to ignore the information from the past for PG&E. But we've always felt it was very pertinent. But it's never gotten any kind of credibility because it was installed in 2001 in Oakland at the Elihu Harris Building on a network system with Rule 21 5 percent import. It was a mistake PG&E says.

Okay, that's fine. If we need to correct it, let's go back. But we don't need to correct it. It's just, we have to ignore it. Okay. But we have information, so let's look at it. Well, we look at it and there's been no problems at all.

So it sets a bogey that perhaps Rule 21 standard 5 percent works. So we're factor 6 times that now in San Francisco. Meaning we've got to buy a lot more power from PG&E and our engines run less. We'll be patient with that. This industry, if it takes ten more years to bloom, we'll be there.

But we need to be reducing the number on a logical agreed basis. And we set in our Rule 21, I mean in our dispute resolution agreement, we set the conditions for monitoring. We agreed how often we would meet. And we agreed that we would reduce the number conservatively on a slope to a point where PG&E became uncomfortable in our first meeting back at the trough, and it felt like interconnection in 2000. It was the wild west again. No rules, no respect, no consideration of what we had agreed on.

One of our biggest points at Real Energy was this document needs to be public. I don't ever want to see Bob Panora or Kevin Best go through this again.

Well, it's a public document, signed in front of God and everyone, and it's not on your radar as an input document. Sources of documentation up there did not include our dispute resolution agreement. It's the one and only document that I know of in New York, Boston, and we're fighting this battle in all utilities in the northeast, it's the one document that really is meaningful. And I don't even see it on the radar.

So, I guess we need clarity and we need certainty, and the investment community will come in droves. And you will see DG. It's not a large lumpy investment. It's a very small, incremental investment that can be very useful for this grid. And I believe we'll figure it out. Particularly if we incent the utilities to figure it out.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you for your comments. I'm not quite certain how to respond. I find them quite upsetting. And certainly we will take steps to assure that the information you can provide is incorporated in our review.

But on a larger scale, I think they're quite troubling. I'm not aware of any member of this Commission or any member of the Public Utilities Commission, any Committee in the State Legislature that has suggested that we go slower on distributed generation. In fact just the opposite seems to occur quite frequently.

And it's painful to hear the inquiries in an Austrian accent, but consistently it's why isn't this moving quicker. Why hasn't the state done more. Why can't we remove some of these barriers more rapidly.

And I'm quite mindful of the need to

safeguard the physical safety of utility employees, and also the provision of electricity to other utility customers. And I think those are important priorities for the state to secure.

But, given that, it seems to me, from an institutional standpoint, we need to do a lot more. And I certainly appreciate your having brought up several things that we should direct our attention to this morning.

COMMISSIONER BOYD: I just want to echo that sentiment. If you were at the -- as you say, you were at the meeting earlier this week, you know where I'm coming from publicly on the subject of distributed generation. And the purpose of this get-together today is to receive all this input, positive and negative.

And I appreciate your input. As Commissioner Geesman said, I don't think there's a Commissioner in this Commission, and certainly in a majority of the PUC that doesn't want to see this move. And that's certainly is the attitude of a lot of other places.

So hopefully we can aid and assist in getting this resolution a little more quickly. That's the role, often, of quasi-regulatory and regulatory agencies. If we hear the call, we'll respond.

PRESIDING MEMBER GEESMAN: What's next, Scott?

MR. TOMASHEFSKY: I just wanted to close off this item. Does the Committee have any general opinion on the three disputed areas, at least in this area, which focus on the need to provide some justification and rationale for various decisionmaking? I think it's similar to what Kevin and Bob have been alluding to, is that even to the extent that the decision is that they can't move forward without these changes, that there's some sort of documentation which is provided that can be used to advance the learning curve.

PRESIDING MEMBER GEESMAN: We're going to want to deliberate a bit on that, and probably not respond in this meeting, but certainly respond on the calendar that you set forth earlier in terms of our formal reaction.

MR. TOMASHEFSKY: Okay, great. And also we'll have the advantage of having additional comments if the parties want to provide them.

COMMISSIONER BOYD: I've asked for my

black robes to be brought down here so I can --

(Laughter.)

COMMISSIONER BOYD: -- sit here the rest of the day.

MS. JONES: Let me ask a question. Kevin, have you provided the agreement that you came to and the documentation for that for the record?

MR. BEST: Have I provided it today? Not physically today, but it's a well known document, Rule 21 uses it regularly.

MS. JONES: Okay, so we have access to it?

MR. BEST: Yes.

COMMISSIONER BOYD: Is it docketed in this, Scott?

MR. TOMASHEFSKY: No.

COMMISSIONER BOYD: It is not?

MR. TOMASHEFSKY: We can; if it's provided, we will.

COMMISSIONER BOYD: I think that's a necessity now.

MR. TOMASHEFSKY: Absolutely.

Okay, we will switch to our next panel. And we're going to keep Kevin there, going to keep him on the hook for a number of these. And, Bob, if you want to participate in interconnection fees, you can. If not, it's up to you.

Grab a seat. Kim Whitsel from PG&E. And Gerry Torribio from Edison. Mark Moser is still not here, so if he comes he's welcome to join.

And starting this discussion let me say PG&E has been nice enough through this process to be the guinea pig of interconnection fee data, upon which we have had a fruitful discussion debating the dollars and cents that are in each of the various pieces on the chart.

I'll start off with Kim Whitsel, and I'll put up their one-pager that we do have. And then we'll just go around the table again.

MS. WHITSEL: Good morning, Commissioners. My name is Kim Whitsel; I'm the Manager of Generation Interconnections for Pacific Gas and Electricity. I've been in this role for about a year. We actually facilitate all of the interconnections from the small solar residential all the way up to the large commercial power plant, so we see everything in between.

PG&E did submit costs for

interconnection. Those are costs based on data that we've been collecting over the year. We actually started collecting more detailed costs starting in 2003.

We submitted those interconnection costs both for the distributed generation order instituting rulemaking, as well as here to the CEC's whitepaper that you see today, I think those costs you see in table 3.

MR. TOMASHEFSKY: And that's on page 25.

MS. WHITSEL: If you look at table 3 you'll see that the costs there significantly outweigh -- the cost to interconnect distributed generation significantly outweigh the fees that are associated for the review, both the $600 and $800 fees for initial and supplemental review for Rule 21 non net metered projects.

Although the $800 and $600 fees do not cover all the costs required to interconnect, PG&E does support retaining that structure as it exists now, as long as the CPUC deems that it's a beneficial ratepayer expense from that standpoint.

We did want to shift a little bit of gears, though, on pre-parallel inspections. That is the part of the process where PG&E comes out and inspects to make sure that everything is safe and reliable. It matches what the customer has submitted. All the equipment is working properly. All the wiring is working properly. And that we have a definitely the main part here is safe and reliable service.

What we've noticed in these inspections is that customers are often not ready to perform inspections. They have called us out and scheduled us to come out to inspect, and either they're not ready technically, the equipment is not running correctly; the wiring is not correctly wired; or they can't get their unit to run correctly.

So we've had some multiple trip problems in this situation where we've had to go out to sites, some cases 10 or 11 times, to make sure that the customers are interconnected correctly.

Having said that we propose a change to the fee structure that would allow PG&E to charge customers for additional trips. And we know that that would need a tariff change to make that happen.

We think that the initial supplemental review fees currently could cover the one trip cost, but we believe that there should be some incentives for customers to be ready, instead of running up the costs associated with this interconnection.

So we'd like to see less cost shifting to ratepayers in this case. And we feel that the only way that customers will be ready that they have to share in that cost structure.

PRESIDING MEMBER GEESMAN: From the numbers that Scott had on his earlier slide, I see that you've had 135 Rule 21 projects interconnected since 2001. How many of those involve multiple pre-parallel trips?

MS. WHITSEL: When I talked to our folks in the inspection group, we have about 95 percent of our projects have multiple trips.

PRESIDING MEMBER GEESMAN: And how many of those 95 percent more than two?

MS. WHITSEL: We average about four to five.

PRESIDING MEMBER GEESMAN: You average four to five. And is that an empirically sound estimate, or is that an anecdotal --

MS. WHITSEL: Do I have the data here, right here, to support everyone of those? No. We looked over the last year, looked at some of the data, and that is what I got from my inspection group. And that is also what supports what you see there as the $10,000 per project on these inspections.

And just to give you a little bit of clarity, as well, on these numbers, it says projects that are interconnected. So we took all the costs that we have and divided by the numbers that were interconnected. There's a large percentage that don't ever go through, but you spend a lot of time and effort working with the customer to try to get them interconnected.

PRESIDING MEMBER GEESMAN: So, if I divided the costs by that larger number then the $10,000 would presumably be lower?

MS. WHITSEL: Right, but by the time that you get to interconnection typically those projects go through.

So interconnection costs are pretty true to the number of projects being interconnected.

PRESIDING MEMBER GEESMAN: Thank you.

COMMISSIONER BOYD: More than the cost, you've accrued quite a bit of experience obviously it sounds like, in terms of visiting these kinds of facilities.

And Scott and group, I don't know if your working group has debated this or discussed this happenstance, but are you accumulating a knowledge base of what the difficulties are? And is there some need for guidance, training, or what-have-you to mitigate against this being the rule rather than the exception in the future? Does the industry -- does some segment of this industry need some help with regard to dealing with this?

Is this poor electrical engineering, or is this poor performance on the part of contractors who are connecting and so on and so forth? Is this reading the blueprints upside down or et cetera, et cetera?

MS. WHITSEL: I think it's a combination of a few things. One, the level of technical expertise of folks who are helping customers interconnect. You have some customers who select contractors or developers who are very good at doing their job, have a lot of technical expertise.

But I think a lot of the problem comes when you bring in folks who don't have that kind of background and will look at plugging these things in as a very simple process, which it's not.

I think the other thing, too, is that we've noticed not only on these size projects, but also even on the large merchant power plants that when PG&E has requirements that have to be installed, people will sometimes try to take shortcuts not to have to have that expense to see if they can get approved without it.

So we've had that happen before. We've required certain equipment and it's not out there when we get out there.

COMMISSIONER BOYD: Thank you. I'm sympathetic to this problem and to your need there. So we need to delve into that a little bit more.

MR. TOMASHEFSKY: One clarification actually, Kim. Could you describe who all is involved in a pre-parallel inspection, and not just the utility portion of that, the building permit folks and all those other folks that could cause the second or third or fourth inspection?

MS. WHITSEL: Well, the building permit folks typically go out prior, you have to have a permit before you go out for the inspection. So, it's typically the customer and their representative who's out there. And sometimes they have a third party test group out there to support them, sometimes.

PRESIDING MEMBER GEESMAN: Anybody care to share with us the experience from the other utilities with these pre-parallel inspections?

MR. TORRIBIO: Good morning, Commissioners. I'm Gerry Torribio with Southern California Edison.

The pre-parallel inspection I would say in our experience does not loom as perhaps as big an issue, but I would echo the experience that the interconnection does require several visits typically by our field engineers as part of the collaboration.

I would also say that our experience tracks that. There is a range of experience levels among the contractors. There are new entrants into the market all the time, so there's a perpetual learning curve.

Most of the projects numerically that are interconnected are not the precertified projects that were discussed a little earlier today. So there is some more hands-on engineering and inspection than might be the case strictly with the precertified units.

Another factor I'd say that maybe masks our vision of how efficiently the engineering is being done is that certain projects have a rather leisurely timeframe, not because of technical problems, but because they may be tied in with a construction program of the customers. That sort of a thing.

So we don't have a metric that tells us that this project is aged or it's going too slowly, and there's therefore a review problem.

I guess a key part of my experience with our projects would be that we could use better cost tracking so we can actually quantify what we're talking about rather than anecdotally sensing how things are going.

PRESIDING MEMBER GEESMAN: Thank you.

MR. TOMASHEFSKY: Do you have any other comments, Kim? Okay, Gerry, the floor is --

MS. WHITSEL: I do think the certified, I just want to echo the certified unit is -- I think the feeling was when we started probably down this road that a lot of units would go and get certified. If you have people who are putting these units in across the country that you'd have a lot of developers who would go and get their unit certified, because it would make the process a lot easier and quicker for everyone.

But that is not the case right now. There is no, I guess, financial incentive currently to aid in that process of getting more units certified. Because that would certainly quicken the process.

COMMISSIONER BOYD: I'm a little bit curious whether the problem we were listening to in the first panel, and the fact that perhaps some utilities are extremely cautious or conservative in their approach and fearful, perhaps, has more to do with the issue you just brought up than it has anything to do with the fact that there's a good certified machine. Although Mr. Panora had had a case in point.

I mean how much is one area infecting the other area? When we get all done with this thing, these things are dead on arrival it's almost beginning to sound like in some cases, and that's just the opposite of what the society of this state desires, quite frankly. And what the policy decisions have been made, as well.

And maybe some of our other speakers can address that, as well; not just putting you on the spot. And we're not even but an hour or so into this thing, so I don't know what more we're going to dig up today.

MR. TOMASHEFSKY: We keep you in suspense for that. Gerry, do you want to make some comments or are you done with your comments?

MR. TORRIBIO: I'm done with my comments, but, Commissioner, I missed a word or two at the beginning of your questioning. If you could repeat it, please?

COMMISSIONER BOYD: Well, perhaps I wasn't too -- in the first panel we were listening to the problems of we've got these precertified packages that have gone through a lot of engineering and we have very competent firms. And, you know, the expectation that they can be put in place and away we can go.

And yet they're having great difficulties and there seems to be a lot of bureaucratic hurdles put in the way of doing this. And fear and conservative approaches on the parts of the utilities and what-have-you.

Well, I'm wondering if the experience we're addressing in this panel doesn't infect their attitude about the whole arena, and that you're -- I'm looking at Mr. Best or Mr. Panora who are holdovers, if this just isn't spreading throughout the whole system.

And as I said, we're not even into the rest of the issues, so maybe they all add up and the dominoes are falling in all kinds of directions.

But I worry a little bit about -- I mean the idea of certifying something and putting it in place is something I'm very familiar with. And that should work.

We heard there were some problems, and I didn't commit myself because I wanted to hear -- I want to pull this whole iceberg out on the table today, and we're only -- I think we're still above the water.

But I'm just beginning to wonder if there aren't a lot of, you know, interconnections between the issues and I'm just trying to get a sense here perhaps from Mr. Best or Mr. Panora that they've detected that, as well.

I'm trying to get away from formulating

the idea that utilities don't like DG and are just out there frustrated. And, you know, I don't come in here with that perception, I don't want to leave with that perception. But the first panel was, you know, disturbing to some degree. And this panel is disturbing, this so far in a different kind of way, that, you know, we've got people out there who don't know what they're doing.

And I've experienced on a large cogeneration facility in this state that was put into place during the electricity crisis that we begged for anything and everything we could get. It had a lot of startup problems, and had to fire contractors and start over again.

So, we have multiple problems here, perhaps.

MS. WHITSEL: I just want to, I know that that folk, they're probably going to answer your question -- I think what you have here, too, today is probably the folks who've had the most problems who've come here today. But I think the vast majority of projects that come through the door, certified or noncertified, end up not having the hitches along the way.

So I just wanted to throw that out there.

MR. TORRIBIO: If I might add just an addendum to my comments, it seems to me from our perspective that the cup is fuller than it is empty in these interconnections.

One surprise to me, as a member of the working group, given the real emphasis and enthusiasm on precertification as a way to really fast-track projects in developing Rule 21 was the outcome that so many of the projects that come in our door as applications are not precertified.

And without getting into speculation about the chicken-or-egg effect, and I do understand it's an expensive process for a manufacturer to go through that for a unit, what I see is that a lot of the projects that we're getting are larger. And they tend to be rather specifically applied. There seems to be a reliance on more traditional engineering rather than one size fits all.

Now, I know the manufacturers, I think, of some of the modular units that have been precertified which say that they can probably put a combination or a stack of multiple units to do whatever a stand-alone conventionally engineering system would do, but just on the receiving end of the applications these are -- what I'm just seeing is that the market seems to be telling us, or at least the customer base is telling us, that they like to install both precertified and the noncertified.

And the noncertified, and I must say I'm speaking from the utility perspective, that does not signify a kiss of death when an application comes in the door. That's so much of what we get. People don't tighten up, I think, and freeze up at the controls. We've had to get used to those, as well as the precertified.

That's all I wanted to add.

COMMISSIONER BOYD: I heard some discussion in the first panel about incentives. And I'm trying to couple incentives and certification into, I don't know, a fast track and a medium fast track and a slow track or what-have-you, but we're just barely into this. I don't want to -- which is why I don't want to make any rash judgments too early in the day on what we should do, what the solution to some of these problems are.

MR. BEST: May I make a brief comment?

COMMISSIONER BOYD: Please.

PRESIDING MEMBER GEESMAN: Please.

MR. BEST: First of all, I don't think we've ever applied for a precertified product. This is not an industry yet. I mean you're looking at a normal year of 80 megawatts. That's $160 million. You know, we're just getting started here.

So there aren't a lot of manufacturers throwing precertified products out. Tecogen is the exception. I don't think we've had one precertified. All of ours are custom engineered. We're in the infancy.

However, I'll say that at SCE, our last interconnection, approval took ten days. So, you know, that's a far cry different than where we were prior to Rule 21 efforts.

Kim, poor Kim, you know, she inherited us when she started. And right in the middle of our -- and I just would like to underscore the accounting systems for cost tracking are deplorable. And she knows it, we all know it.

There needs to be an incentive for the utilities that want to do business this way and figure it out and do it efficiently. Because right now it's kind of a hobby they're forced into. And I really would encourage them to be incented, because, you know, the customers that they're serving have, you know, very few skill sets in their toolbox. I mean we go to one engineer in this state, one electrical engineer. And we've tried to go to different ones. We always come back to the one guy to fix it. There's one resource in this state in my opinion for tight electrical. Well that's not an industry. And that's what they're suffering.

So, I would just underscore that certification is great, but you have to have an industry first, or they won't come. I think Bob's the only guy you can call an 800 number and order a prepackaged unit.

There's an illusion of simplicity in this business. It attracts a lot of people because it just looks simple. Throw in an engine, hook up some pipes. And it's very difficult behind the veil.

MR. WHITAKER: If you don't mind, I'd like to give a comment on certification. Because that was an area that I was responsible for in the initial Rule 21.

When we developed the certification process we knew full well that it really applied to the small, inverter-based systems; would apply to medium size and probably would not apply to the larger systems. And, you know, it was just the reality.

We did take a step forward and implement this as a certification process. We took existing test procedures and said let's do a certification process.

It's only implemented in California right now. And so you're exactly right, there's very little industry out there supporting that. Tecogen was able to take advantage of that, and we commended him on that.

On the other hand, what we're doing right now on the national basis in IEEE is at this very moment we are voting on a standardized test procedure for certification, the certification test for this equipment. And that ballot should be done -- well, the ballot will be done on the 16th of December, and we should know before the end of the year how that turns out, probably some provisions of that.

But we expect to have that document finalized by this summer. And now we'll have a national standard that can be used for the certification process, rather than just what the silly guys in California put together.

And I think it is part of this development on the committee, I'm on the writing committee, includes Cummins Engineering, which is a large diesel generator manufacturer; ASCO, which is a large diesel synchronous machine provider. They are both interested in this process. And I think once it is established on a national basis and the market is therefore made, we will start seeing this.

MR. PANORA: Can I comment, as well?

PRESIDING MEMBER GEESMAN: Please do.

MR. PANORA: Just a couple of points. As far as the interconnect cost, repeated trips, you know, and that preparallel inspection goes, I think in our case it mostly is rather smooth, goes smoothly. I believe that's the case; I haven't heard many problems.

But, on the other hand, it's a case where the utility is sort of self-imposing the difficulty. Our machine is precertified. It gets factory tested for its safety and certified by a QC department to Rule 21's test.

And then it goes into the field. And the whole preparallel inspection sort of revolves around testing this additional redundant system, which I don't even know why it's there, you know, I still don't know why it's there. And that's what the whole game's about.

And if the certification system is working properly that step would be so routine it would be simply checking the machine that was already tested at the factory once again, and just in and out. That always goes smoothly.

It's the redundant system that, you know, again it's self-imposed by the utility. So, just wanted to make that point. It doesn't have to be that high. It can be absolutely trivial.

And I think the fact that our experience has been so difficult would really discourage anybody from following the same path that we took. Because at the end of the day it didn't really buy us the promise of a simplified interconnection. So it's one of those things where it's kind of hurt the industry a little bit.

As far as other states go, just a

clarification on what Chuck was saying, in Massachusetts the rule says if you're certified in California under Rule 21 you are certified in Massachusetts. Massachusetts doesn't feel it has the funding or the ability to certify people, so they're looking to this group to certify for everybody in the country is really how it may shake down.

And we are certified in Massachusetts by having Rule 21. We're certified in New York State under their program, which follows the IEEE system. So we've done all those certifications. And for the most part, Massachusetts and many parts of New York, you just have to simply have an inspection that is routine; no extra equipment. And we go in the way that I think was the intent of the writers of Rule 21. So I just want to add that as background.

And the new system, the new IEEE versions really won't affect the certification that came before it, other than we just have to repeat what we already did in a slightly different way. So it's not as if there's been a lot of new things uncovered. It's basically just refined a little bit. We're not -- we're going to go through it again. We're going to do it again because I still think it is absolutely the key to having small DG successful.

I mean what Kevin does is probably 300, 400 kilowatts and above, I suspect it is. My whole market that I want to see develop is the small nursing homes, the schools, the places that cannot afford an electrical engineer to be putting that much time and effort into it.

So I think the certification system, and making it work right, preserving it is really the key to expanding the market. And I just want to, again, I want to commend the Rule 21 people for inventing it. I mean that's fabulous. But, again, we don't want to lose it, we don't want to let it slip away, because it will be -- if we're successful, Tecogen's successful, there's nothing we're doing that's difficult to copy. Anybody can copy us. And we can see our competitors coming right behind us, and that's fine.

But you don't want to set up a system where everybody sees all the hours at my back; I'm not going to do down that trail, so -- anyway, that's my little two cents worth.

COMMISSIONER BOYD: Bob, you've made

your point well in two sessions, and I frankly am on your side in the sense that precertification, certification should mean something. And it should speed up the process.

But I must admit I have some sympathy and experience second-hand, or what-have-you, or I guess I just know the human species reasonably well, that it's not just a plug-and-play situation. That in wiring things or plugging them in, you know, -- I had a house built once, I know what the electricians can and can't do.

There is a problem there. And there may be some institutions can help us with that problem. But then, you know, the wrong plug on the end of the cord, the simplistic analogy, can shut down, trip the system. So it's not so much what's inside your box, and the redundancies that are required there, which I guess we have to address.

But it's facilitating a new industry, I guess, and being able to wire it up right. And it looks like maybe we have a major problem there. I mean when somebody can really screw up a 49.9 megawatt or bigger than 50 megawatt giant cogen system, I know that, you know, we have some competence problems once in awhile.

And Mr. Best has said he's got to chase down this one person. So, we may be identifying something that there are a lot of other institutions out there who should be helping us with, or helping you all collectively, us all collectively, with it.

Anyway, I appreciate the dialogue here. This is truly a workshop.

PRESIDING MEMBER GEESMAN: What's next, Scott?

MR. TOMASHEFSKY: Just a couple of closing comments. It may lead to one or two additional questions.

First, the notion of the specific costs. A lot of this discussion and even this table, in a different format, is part of the testimony in phase one of the PUC's portion of this proceeding. And so the development of the cost/benefit methodology is going to look specifically into a lot of these areas. But it's important to have the discussion on preparallel because it does have some impact on how we address these issues.

The other area that we have focused on but not talked about too much here was the appropriateness of the $1400 fee. We've made the recognition that while the $1400 is not covering the costs on a global basis, if you take the assumptions that are built in here you can see that the costs are greater. And we can quibble about the numbers that are in here, but we know that there's some subsidy in some portion.

And so a lot of the discussion we have had has raised the question is it worthwhile to change that fee structure right now. And the fee, itself, was designed with the intent of making sure that people just don't waste everyone's time by filing these applications, but not making it so prohibitively expensive so that these reasonably easy to interconnect projects can be interconnected.

And I think the general consensus was that there wasn't a need to change the fees at this time, although it's still an under-review type of approach. So I think you just need to be generally aware of that. That's the general recommendation.

The one other item that I wanted to add is -- and we do describe it in some respects in terms of the collection and tracking of costs.

The reason why PG&E was able to provide this data is that when the PUC ordered the utilities to go ahead and collect cost tracking data for several months in late 2002, PG&E set up a tracking system to deal with that.

What San Diego and Edison did is they, in essence, complied with the terms of the tracking, but didn't set up the same type of process. So, if you're going to look at this cost information for purposes of making policy decisions, it probably needs to be some specific direction on what's going to be tracked and how consistent it is across the three investor-owned utilities. So, just another comment.

I don't know if anybody wants to add to that, but that's, in essence, the two or three comments I wanted to close this with.

Any other comments at all? Okay.

PRESIDING MEMBER GEESMAN: Why don't we go to our break.

MR. TOMASHEFSKY: I think we're ready for a break.

PRESIDING MEMBER GEESMAN: We'll reconvene precisely at 11:15.

(Brief recess.)

MR. TOMASHEFSKY: Okay, welcome back, everybody, from the break. This next discussion is what we would classify as an emerging type of construct for DG systems. And it really, as I said before, it's driven in large part by the expansion of the net metering program to 1 megawatt for PV and wind, and then add fuel cells and bio on a pilot basis.

What we have now are different types of configurations of systems that have some technical aspects that we're going to address first. Gerry Torribio is going to walk us through some of the technocrat side of the fence. And then from that point we'll also shift over, if there's going to be any other comments from Dylan Savidge of PG&E or Mike Iammarino at San Diego, and then we'll switch over to Tom Blair from the City of San Diego, who has a project where a lot of this issue has actually emerged. And I think it serves as a very good flashpoint to see how these projects can be configured and some of the issues that we're needing to address.

So, with that I'll turn it over to Gerry, and I'll push your slides.

MR. TORRIBIO: I am not going to propose

to repeat the material that was in the Rule 21 working report, but rather I wanted to try to just frame an overview of net metering and how it works pretty quickly. And then go to the unique types of projects that we're now starting to encounter.

As interconnection facilitators, we at the Rule 21 working group have taken on the task of looking at the interconnection issues associated with combined technology net metering.

I'd like to just define the term a little bit. We're going to be using the term NEM eligible and noneligible, or NEM and nonNEM. And what we mean by NEM, net energy metering, here are those technologies which have been identified in the legislation such as photovoltaic, wind, dairy digester biogas and the fuel cells on that experimental net metering tariff. So these are the core net metering technologies, any of which are eligible for interconnection. And they have a special tariff treatment which includes the netting out of export power against customer bill exemption from review fees, interconnection, costs and so forth.

Scott, if you'd go to the next slide. Just in -- we ought to talk about not combined, let's talk just briefly on simple NEM. We've got the load represents the electric equipment that the customer's serving at their facility, whatever they're using.

The PV there would symbolize a photovoltaic array. And basically when the sun shines, in the case of this PV, they would be serving some or all of their load possibly. There may be exports which would go -- that M is a meter. That's the bi-directional utility meter which is central to administering the current net energy metering tariffs.

And that little delineation which you'll see on a couple of more pictures, it's just -- that dotted line is just the borderland between the utility distribution system or grid and the customer's facilities.

Just a passing comment here because we're about to talk about an emerging type of project that presents issues to us. In the initial statistics that Scott Tomashefsky shared about interconnections, I believe net energy metering types of projects were not included in those. But I would say that we at Edison have well over 2000 of these simple -- by that I mean a single technology -- projects interconnected.

Where I have PV there, it could also be one, and one only, of the other technologies. Typically we get a wind and nothing else. Or we get a fuel cell and nothing else right now. But that's not necessarily going to be the case as we go forward.

Scott. This is the archetypal combined technology net energy metering installation. And if you look there we've got photovoltaic again, or by that I really mean a net energy metering eligible technology. And then we have, for the G there I've got nonNEM. That could be a microturbine; it could be a gas-fired engine; it could be diesel; it could be a number of different types of generation which have not yet been granted status by the Legislature for net metering tariffs.

This is the situation. I'm going to advance the slide to one more, and that will -- this third slide will kind of scope out the situation. And if it's helpful we may go back to them when we talk about issues or situations we have to deal with.

Here's one where we have two dissimilar

net energy metering eligible generators. We've got dairy biogas, the BG, and we have photovoltaic again. Otherwise the physical characteristics of the installation are pretty similar. We've got those generators plugged into the system on the customer's side of the meter, serving their load, doing their thing. And then we have the interconnection. And power may be exported at various times.

A key thing when we look at these dissimilar technologies which are net energy metering eligible, is that the tariff structure is not the same for all of them.

The customer right now who is on a photovoltaic-only tariff receives, when they export power, the full bundled utility retail rate as credited against their bill.

By contrast, under the biogas net metering legislation and the tariffs, they are credited with the generation component. So we're going to get into this a little later in the presentation, but you need to, in this case, one would need to make some decisions about which rate you credit, which part of the exports that pass through the meter.

Maybe at this point we could go to the next slide and just run through the issues, because we've addressed, or we've at least encountered both technical and nontechnical issues. And I think the fundamental thing we've concluded is that the technical issues are not show-stoppers, they're not insurmountable. Whereas the nontechnical issues will require some work.

The technical issues, integration of functions of certified inverter on photovoltaic system with noncertified generator to maintain anti-islanding protection. What this is about is the fact that the net metering types of projects we've had interconnected thus far, typically the small solar, have an inverter package which combines the functions of both electrical protection.

It allows export to the grid when the grid is there, which is part of the normal output cycle of the photovoltaic array. But if the grid is down for some reason, if there's an outage, the protection in that inverter provides what we call anti-islanding function. It keeps power from being injected out there where somebody might have to work on the grid. And that's a key safety thing.

The technical issue that we have raised here is that we can conceivably have a combination of a unit, let's say a photovoltaic unit that has the inverter package with which we're so familiar now, self-contained; and perhaps a relatively large synchronous generator, which would require its own electrical protection. And some work will need to be done in making those two compatible so that they continue to provide anti-islanding protection.

I think the bottomline on that one is that as such installations are reviewed or encountered, from a technical point of view what will be required is some additional review work. That's all.

And it gets us back a little bit to our discussion about certified versus noncertified. The smallest net metering type projects, photovoltaic, are on a very fast track because the inverter packages are all certified, listed with the Energy Commission.

If you add to that unit something that's not, then it has to come off that ultra fast track and get a little more scrutiny. And I don't think we have an experience pattern yet on how we would do that. But the technical people in our group seem to concur that it can be done. It's not insurmountable.

A second point here, additional metering may be required for tariff administration. And we're going to get into that a little bit. When you're talking about different rates applying possibly at the same site there's going to be a need to separate the streams or distinguish between the outputs of different generators.

Now that's not a big, necessarily a technical issue. It's just going to be a little more work to be done on these installations where now a typical solar, the smaller size solar photovoltaic or wind installation has very little, very abbreviated review.

Many of our customers have, they have a bidirectional meter at the point of common coupling already. It's in there, and it just needs to be programmed. It's not necessarily true that we have to go out and even change the main meter right now. But there could very well be the need to put in another meter or meters.

A third one is on the large combined technology systems. And by this you might envision perhaps a dairy biogas digester engine; maybe several hundred kilowatts with a small solar. It would be possible that there would be continuous, rather significant levels of export to the system. Not just occasional.

That type of operation will require additional review if we recall that our Rule 21 process has been predicated pretty much on most of the projects being nonexport, serving only own load.

So, once again -- oh, another possible issue on this, just as we would do on a -- have done in the past on qualifying facility projects that export continuously to the grid, just as we would do on a merchant plant, whether the really big, 50 megawatt or bigger, or even on ones in the megawatts range, we may have system upgrades or installation of facilities to protect the grid that would not be required were the same size of generation nonexport.

This is not a new frontier, technically. It's just something to be reckoned with. And I think it's probably more, for our purposes it's more of an issue that translates into how do you allocate the costs of reviewing, how do you handle it. Not can you do it.

Scott, could you go to the next one. These were the nontechnical issues. Maybe they could be called institutional issues like my tariff, contractual. I'd say this first issue, it's under this Roman numeral small i, should the nonnet energy metering generator operation be limited when a combined facility is exporting to the grid.

That's a key one. We'll touch on this and then go back to one of the pictures maybe, just to flesh it out.

The Public Utilities Commission examined that issue in the previous DG OIR. Basically a customer or some participant in the proceeding wanted to install I believe it was a microturbine. I'm not sure what it was, but it was not solar.

And so the issue arose whether that could even take advantage of the net metering tariff, or should the combination of those two technologies at one site exempt it and require that it be interconnected as a distributed generation project without the special net metering tariff treatment.

In that decision 03-02-068, the Public Utilities Commission suggested a way of protecting or balancing the ratepayer interests and the customer's needs, which I'll illustrate in a second on the drawing, and then we'll go on.

There are other approaches, and we'll try to sketch those out on the drawing a little bit.

There's an issue, what we have referred to as the stacking issue, that if in a combined technology project, for example a gas-fired engine and photovoltaic, it would be possible to serve all or most of the load of the customer's needs with the gas generator, and then basically the photovoltaic array would be in the exporting mode much of the time. The concept is stacking of the solar on top of the gas generation in a manner of speaking.

If we could back -- could we backtrack to the one that showed -- the next one back, Scott. Yes. Just talking a little bit about how to handle exports. If you can imagine two generators, one eligible, one not. Of course, the electrons don't know who they belong to. They only know that if there's more power generated than there is load, it's going to flow out through the meter.

So the Public Utilities Commission went so far in the decision I referenced to address the fact that the entire export, including whatever came from the noneligible generator, probably shouldn't receive the net energy metering credit.

They suggested that a protective device be installed somewhere where the laser spot is holding, a reverse power relay which would sense that if power was being exported -- began to be exported, it would trip the noneligible. Now, in a rather simple way that would guarantee that if anything left the site, it was going to be from the solar, because the noneligible generator would be tripped.

That solution has come under a lot of discussion in our group. It's not universally acclaimed.

Another solution might be -- I'm just going to throw these out -- another solution might be to just not attempt to give any restriction to power flow out. Let whatever flows out, flow out. Meter, separately meter the noneligible and the eligible generators so that in some way the export that the utility reads can be apportioned, and the credit can be given on an amount of export which is commensurate with the eligible. And the other is not compensated.

Another approach, rather than -- a third approach would be to have sort of a limit built in where both generators can keep exporting or can keep operating up to the level of the eligible. So, let's take an example. Say we had a very small solar array. Say we had 10 kilowatts and we had a, I don't know, a 200 kilowatt gas generator.

The interconnection would allow 10 kilowatts to be exported, irrespective of where it came from.

If we can go on, I think, to the other issues. These are a combination, I guess, of issues and perhaps principles that we would espouse in this.

The nonexport or inadvertent limits on nonnet energy metering generators should be addressed, or should be maintained. Under current Rule 21 there are limitations to the extent to which generators, in general, can export to the grid, nonexport or inadvertent very minimal export. And the purpose of this is to allow simplified interconnection requirements; less rigorous, less expensive than we would for a continuous exporting project like a merchant or a QF.

Insurance provision for generating facilities. If we're going to have net energy metering eligible generation and noneligible, well, net energy metering tariffs currently exempt the customer-producer from furnishing a liability, evidence of liability insurance to the utility. Not so the noneligible. That needs to be addressed. Is it split? Is it apportioned?

Phased installation of net metering and nonnet metering should be addressed. There are scenarios where somebody could have an existing DG project, distributed generation, gas-fired let's say, or some other technology that's not under net metering. And they want to go back and retrofit a solar panel. How do we phase in the review and how do we deal with that costs.

Additional metering required to administer combined technology. If you'll recall where I showed you that hypothetical where we had a dairy biogas and we had a solar installation at the same customer site. That's an example of one where in addition to the meter at the point of common coupling, we're probably going to need some meters down in the site to tell us what the two technologies are doing so that we can apply the right credit to the right amount of generation.

We have a note here that that might require amendment to the Public Utilities Code. Section 2827, which now pretty much defines the legislative basis of net metering. It states that with the agreement of the customer utilities may install a meter down within the plant on the generator. But it's at the utility's expense. If they need it for tariff administration. For simple single technology projects we haven't needed that for tariff administration.

If we begin to interconnect projects like this and we need this so that we can figure out the customer's bill, I think it might be timely to revisit whether that should be charged to the customer.

Review and facilities costs are non NEM generation. This is going to be, it's down near the bottom of the list, but this is going to be significant. We charge, under Rule 21, the application fees, the basic $800 or the supplemental. For more complex projects there may be additional interconnection studies that have been discussed in other venues.

The typical net metering project thus far has needed fairly cursory review. But as we get combined or hybrid units the utilities are going to be spending a considerable amount of time on that. So how those classes should be allocated remains to be seen.

Departing load and standby charges applicable to nonnet metering generators should be addressed because the net metering technologies right now are exempt. Once again, do we apportion it based on the generation, or do we exempt them all, or do we charge them all.

And then finally uniform contracts for such a combined technology net metering installation will need to be developed. And we list that as an issue.

In the working group we've had a fairly successful experience in developing agreements that were needed to accommodate distributed generation. So this is probably not much of an impediment.

Once the policy -- some of these policy decisions are made that give us some guidance about what should be done or what should not be done, then the contracts can be written to accommodate that.

That's the extent of the introduction.

MR. TOMASHEFSKY: I'm going to turn it over to Dylan. I'll put your thing up.

MR. SAVIDGE: Good morning, everybody. I'm Dylan Savidge. I work in PG&E's rates and tariffs department. I work in a group that's primary responsibility are the tariffs related to DG interconnection. That includes Rule 21, as well as standby and the net energy metering tariffs.

I'm not going to repeat a lot of what Gerry -- I think a lot of what I have to say here is really in support of what Gerry has outlined here. He's gone into a lot more detail. And I'm covering the concepts more, in a high level.

But as you can see, this issue is very complex. And there are a lot of components. Mainly dealing with process metering and technical issues.

PG&E does agree that the technical

issues can be overcome; it's really more of a process issue and metering issue, as you can see, that still need to be resolved.

PG&E feels -- some of the guiding principles for which PG&E will be operating are we're very interested in efficiency of tariff administration. What we're currently running into now is a set of net metering tariffs that each have their own individuality, if you will. They're not similar; they take some studying for customers to understand, yet alone PG&E and the various representatives within the company that work with these tariffs.

Another point is we are very interested in compliance with the tariff and legislation, and the current proposal now for combined technologies runs the risk of perhaps not fully aligning with the provisions of the legislation, code 2827 and our net energy metering tariffs. That's something we'll need to address.

We're also interested in appropriate cost recovery, and I say appropriate in order to minimize ratepayer subsidies. And Gerry outlined a couple areas there where bringing up issues such as insurance policy coverage interconnection fee appropriations when you have combined technologies definitely needs to be addressed.

We're also very interested in efficiency of our own operations, as well as making this as easy and efficient for customers to understand or experience with the current net energy metering tariffs, as they are somewhat difficult for customers to understand. There's quite a bit of time and effort to get materials out to the general public as well as folks interconnecting to fully understand what their potential benefit is, from a financial standpoint as well as operational.

So, you know, given that we, you know, need perhaps some policy guidance. We definitely will be looking to try to simplify it as best we can, particularly in this particular issue where we have another layer of complexity added to an already complicated set of net energy metering tariffs.

We don't have the answers right now. So, in closing, we fully support the current efforts of the workshop. We find that that's the most efficient means. I think the working group has done an excellent job in the working group report outlining the issues.

They've outlined some scenarios, I think, that covers probably the biggest scenarios we're likely to see, but yet there are many many others that could arise. So we have to be careful as we move forward to develop guidelines that will, you know, keeping that in mind, guidelines that will keep the structure of this solution as simple as possible for ease of implementation of everyone to understand.

We are concerned, we would like to see policy guidance regarding appropriate allocation of incentives, provide for each technology. And Gerry covered that, as well.

And then we also support the CEC's recommendation on the two policy issues outlined at page 37 of the report.

PRESIDING MEMBER GEESMAN: You may have different pagination in your report than I do. I can't find on page 37 of what I have --

MR. TORRIBIO: Have you got the network, does your show the network?

PRESIDING MEMBER GEESMAN: Yeah, mine shows interconnection rules for network systems.

MR. TORRIBIO: Mine is the same as

yours, it shows 35 and 36 would be the -- is that
our conclusion on the net metering section --
MR. SAVIDGE: Yeah, I don't have the
report with me, though.
(Parties speaking simultaneously.)
PRESIDING MEMBER GEESMAN: So, Gerry,
where should I look to pick up those
recommendations?
MR. SAVIDGE: That would be page 35 I
see on this right now.
PRESIDING MEMBER GEESMAN: Okay.
MR. TOMASHEFSKY: And that feeds into
page 36, as well.
PRESIDING MEMBER GEESMAN: Okay.
MR. TORRIBIO: And really, I would just
add that the recommendations, as they're stated in
the report, they collapse or they encompass a
number of the individual issues that we had
highlighted in the introduction. The cost issue
and the operation issue, so they're not at odds,
but they're a little bit less bullet-y in the
report.
MR. TOMASHEFSKY: Mike, do you want to
make any comments at all, or --
MR. IAMMARINO: Good morning; my name is

Mike Iammarino with San Diego Gas and Electric. And being the third guy down the line for this stuff after everything that's proceeded, what can I say, except succinctly ditto on all those remarks.

Only one item I'd like to add that we didn't cover here that has sprung up in San Diego's service territory to add to the complexity of the issues, we still have these things out there we call qualifying facilities that are selling to the utility. And some of those qualifying facilities with the old standard offer contracts are also installing photovoltaic not eligible, behind the same meter.

So what do you do now when you're buying energy from them already, and now they have a facility that has that energy metering eligible? I'm not sure what that answer is at this point. But it's just something else to add to the pot.

MR. TOMASHEFSKY: Okay, we're going to shift gears a little bit here and give a real -- get away from the reality of tariff administration and move to the reality of actually real application.

And Tom Blair is with the City of San

Diego and they actually have a project that they've been trying to put together such an arrangement. And that's kind of put us to where we are today in the context of the issue. And why it's actually now part of the report. This is the flash point.

Tom.

MR. BLAIR: Good morning, Commissioners, and thank you for creating the forum where we can discuss the important issues of improved deployment of distributed generation.

As you know, the City of San Diego has a large number of generation facilities already interconnected under various agreements. We do have one qualifying facility. We have a number of other facilities that are through contracts with third-party vendors interconnected with SDG&E, and selling as-available power.

As a city with over 3000 meters of our own that we pay for each month, we take service under almost every tariff that is available from SDG&E, and have everything from large usage pump stations to small residential buildings that take tariffs under the residential rate.

The issue that is before you really

comes down to cost. If you look at any distributed generation that you plan to put in any building, you're first going to design that based on what is the best cost benefit for you.

The particular case that we're looking at at this one, we designed improvements to 150,000 square foot police headquarters building in downtown San Diego. It started out as approximately a 1.2 megawatt user of electricity.

We did nine energy measures to improve it. Two of those were generation, self generation. One was a 530 kilowatt cogeneration system which used the exhaust heat to drive an absorber chiller of 130 tons.

We also have a photovoltaic system which is only 30 kilowatts, a fairly small system on the rooftop. But again, wanting to try and look at the building, we first looked to try and decide what is our baseload for that building going to be.

So we took the annual usage through all seasons and all the information and estimated what we were going to be able to improve from the other energy measures. Our estimates were a little bit conservative and we ended up conserving more than what we thought.

So the total usage of the building right now during this time of year is about 750 kW. So during a normal workday we will be drawing still a couple hundred kW from the utility, and using the 30 kW photovoltaic system to offset a portion of that during the peak hours of the afternoon in the summertime.

Of course, in wintertime peaks on weekends and peak is not during the time when the photovoltaic is going to generate, so that doesn't help in that particular time of the year.

But again, we tried to size the systems. And what we've been experiencing, and I think you're seeing all the pioneers of the distributed generation industry trying to come to what is the true cost of installing. And we find barriers at the Rule 21 interconnection. We find barriers because the tariffs that are in place right now do not value electricity as it would normally be valued if the DWR contracts were not in place.

So you're not getting the true offset costs that you would typically get from a distributed generation plant in any of the buildings that you're installing them in.

And I think it's clear from the legislature that they desire to have more distributed generation, more peaking solar, more installations. And because of the way all of the various net metering tariffs were developed, they all have different rules which exempt different components.

And maybe it's time to look at all of the tariffs and say they all should be the same; or maybe they should all be exempted; or a policy decision be made that could help implement true distributed generation that would be useful for the building owners when looking at how you're going to try and improve energy efficiency in all your buildings.

We have a number of photovoltaic systems that we've had installed up to 18 months now. I have a 61 kilowatt system on one municipal building, a 55 on another, and two 30 kW systems. We've been using those, our experiences in billing and tariffs and just how they generate, to compile information that we can use in designing future improvements for the buildings that we own and operate.

And also to try and provide information

for the public as they come to us and say, well, what is your experience in doing this. We want to be able to hopefully point out some of the pitfalls and show them ways that it can be easily installed and meet both the utility's need and the customer's need to come to where the utility can gain appropriate compensation for the costs that they have. And so the extra add-ons don't become a barrier to actually installing future sites.

So I would ask that you look at the total of the issues. We've covered a lot of them in the Rule 21 group. And it's been a lot of very good conversations on all of the issues. It does not appear to be a technical problem now in becoming interconnected to the grid. It becomes truly a policy call on what cost is going to be paid and by whom, and how is that going to benefit the overall grid in the long run.

When we install systems we're also installing real time metering with them so we can keep track of what the systems are generating. And trying to get data in that. And I would say that any system that you put in, you need to have some performance measures required so that you do, in fact, gain what you think you're going to gain from that installation.

That concludes my comments, and if I can take any questions.

PRESIDING MEMBER GEESMAN: Do you think any of the legislation establishing these programs provides guidance on these cost questions?

MR. BLAIR: There are cost issues covered, yes, there are specifics in each of the laws. The original net metering law that was established, I think it was AB-2222, years ago that created the first net metering where just turn the meter backwards, exempted most, you know, all of the cost responsibility charges and have led to the current net metering tariffs that are in all three of the utilities.

As the other systems were recognized as also of potential benefit, the biogas systems, the other types of generation, as those laws went through to create the net metering for those, additional cost components were put in that became non-bypass-able, for the utility to prevent cost shifting.

And, you know, at some point the creation of those cost responsibility charges are what create many of the metering questions and the interconnection questions. Because if you didn't have to try and sort out what those charges were, you wouldn't need the extra meters.

You look at the point of common coupling meter and you know whether it's importing or exporting, and you act accordingly.

Most of the systems that we will be putting in are going to be on existing buildings, so the load will already have been well established over the years. And there may be minor changes here and there, but for the majority it's not really new design.

PRESIDING MEMBER GEESMAN: So in your judgment much of what's driving this question, if not most of what's driving it, are efforts to collect costs like the DWR contracts and other things that are supposed to be paid for on a non-bypass-able basis?

MR. BLAIR: Yes, --

PRESIDING MEMBER GEESMAN: It's not a question of the utility recovering its own administrative costs, but rather these non-bypass-able costs that the overall system incurred during the electricity crisis?

MR. BLAIR: I believe they're both

components. You have the component where you're trying to recover the non-bypass-ables. And I think the utilities have taken a good effort, too, at trying to define what does this cost now.

The administration of the net metering tariffs, when they were originally created, cannot be done in the automatic computerized systems for the utilities. So they have someone manually enter our export to the grid against my billing to create credits on a monthly basis. And then once a year reconcile that. It's all done manually. So there are --

PRESIDING MEMBER GEESMAN: Yeah, but I guess -- and anybody else can jump in to answer this, if you choose, as it relates to utility administrative costs it would be my belief that unless the legislation provides directly to the contrary, that when the Legislature created these programs that the presumption was that those utility administrative costs would be recovered in rates.

I think the underlying desire on the part of the Legislature was to encourage the use of these technologies. And certainly that's been a pretty consistent theme at this Commission and, for the most part, at the Public Utilities Commission.

I'm trying to draw a distinction between the non-bypass-able surcharge items where there, I think, is a strong legislative desire against cost shifting, and an insistence that those costs be properly collected from the utility administrative costs. Where I believe there's a presumption that, of course, those are to be recovered in rates. That we ought not to necessarily burden these technologies or these early adopters of these technologies with requirements that would undercut the fundamental purpose of the legislation in the first place.

MR. BLAIR: I would say that's correct. And also, you know, if you look at the different requirements for each and every interconnection, if you view that as an improvement to the utility distribution system, maybe that's a component that should also be recovered --

PRESIDING MEMBER GEESMAN: Well, the PUC has that under review now.

MR. BLAIR: Right.

PRESIDING MEMBER GEESMAN: You know, and we're collaborating in that effort. And I understand it's a complex one, but I do think that's a factor, as well.

MR. BLAIR: The bottomline is it creates barriers to new DG installations for the future.

MR. TOMASHEFSKY: So under that context policy direction has to be given before you can finalize what type of arrangements you're going to have in place.

PRESIDING MEMBER GEESMAN: Sure.

MR. TOMASHEFSKY: And so that's the dilemma that we have.

PRESIDING MEMBER GEESMAN: Yeah.

MR. TOMASHEFSKY: And, of course, part of that is contingent on what happens with the cost/benefit work that occurs at the PUC.

So once you make that determination about whether it's beneficial to grid support, or whether it's an incremental cost, then you can determine whether you roll it into the distribution function costs, or whether it becomes a customer cost.

PRESIDING MEMBER GEESMAN: Yeah, and the non-bypass-able surcharge costs presumably are heavily weighted to the DWR contracts?

MR. TOMASHEFSKY: To a large extent.

There's other ones, as well.

PRESIDING MEMBER GEESMAN: Yeah, I understand there are other ones, but if I'm trying to focus on most of the horse, I think --

MR. TOMASHEFSKY: That's most of the horse.

PRESIDING MEMBER GEESMAN: -- most of the horse is the DWR contracts.

MR. TOMASHEFSKY: Unfortunately, some of the net metering legislation has been inconsistent in terms of what non-bypass-able charge applies and what doesn't.

PRESIDING MEMBER GEESMAN: Yeah.

MR. TOMASHEFSKY: And that's just the nature of having different bits of legislation. So, there's some interesting aspects.

PRESIDING MEMBER GEESMAN: Okay.

MR. TOMASHEFSKY: Tom, did you want to comment just for a minute or two about -- you mentioned about the sizing of your unit, but you didn't mention about the fact that your efficiency gains have been so much that you find yourself now exporting on weekends. And how that has kind of raised the question of when things trip and when they don't trip.

MR. BLAIR: Right. And that's where we came to the combined tariff requirement need. Because we did actually achieve a better energy efficiency than we thought, and with the lower usage on the weekends, since the building is not fully manned, there are lower consumptions.

And we came to the point where we could export the photovoltaics on weekends, in the periods when there wasn't other heavy building use.

So that raised the question of should the net metering tariff apply, or should -- because we're currently, because we installed the photovoltaics first, we initially installed it under a net metering tariff. And then after we put in the cogeneration system. And the cogeneration system, there is no partial export interconnection agreement that can be entered into at this point under the Rule 21.

So, we were taking the tariff right now under an inadvertent export. So we can export for two seconds at a time, but then have to bring down the cogenerator to keep the export, to keep it from going into an export to the grid. So right now we're controlling the speed of our generators to prevent export.

PRESIDING MEMBER GEESMAN: But, again, trying to get back to the underlying purpose of the law, I believe would be to encourage as much export from the PV system as possible.

MR. BLAIR: And I would concur with that.

MR. IAMMARINO: If I may, I think what you said was correct, but that's where we've had this discussion philosophical and perhaps I don't want to get into the form too much, but earlier, Commissioner you said something to encourage the use of these technologies.

And I think you hit it on point. The use of it. And that's kind of where the utilities come from. You use it for your own purpose; rather, in our case here, what Tom is suggesting, in essence, I guess, the simplest way to describe it would be to become a renewable export, at the cost of raising the gas.

So we're not sure we necessarily agree nor understand how that really is helping things. Because the photovoltaic should be used there to supply that load when it's available, and conserve the gas on that unit by having it come down, rather than to pump it up and then just put that renewable out on the system.

And even then we're not sure. If you looked at the configurations of the system, which electrons are going out there, because there's no way of telling at this point in time, because they're just mixed together.

PRESIDING MEMBER GEESMAN: Yeah, I suspect though if I parsed back through both statute and certainly policies of this Commission, and to a large extent, policies of the Public Utilities Commission, and looked at policies encouraging distributed generation, I suspect I'd find for the most part an encouragement of export from those technologies, as well.

Again, just trying to look at legislative purpose and policy purpose and this Commission and the Public Utilities Commission. Understand that has to come face to face with practicality and how to safely administer the distribution system.

But if I'm wrong, somebody point me to a statute or policy of one of the two Commissions that suggests that we shouldn't be encouraging export from these installations, both the NEM and the nonNEM.

MR. TORRIBIO: Could I comment without --

PRESIDING MEMBER GEESMAN: Please.

MR. TORRIBIO: -- saying you're wrong?

(Laughter.)

MR. TORRIBIO: One of the signs of legislative intent that I focused on in reviewing this was the preamble and section -- well, I believe it was AB-58, and I think it was carried forward in one of the others, that talked about encouraging peak load reduction.

And I would just key off of that comment that we -- or that statement, that in encouraging solar, let's say, or we encouraging renewables, they're different -- obviously different applications. We can encourage them as a resource, as an export or as a generation resource. Or we can encourage them as a means to efficiently reduce customer load and customer demand, which indirectly it gets us to some of the same goals.

And as we -- to the extent that we encourage let's say an export application or encourage a resource to start looking like an export type of generation, we get into -- from a, I would say, an operation, utility operation, or perhaps a grid operation and efficiency perspective -- we get into the question of how should we -- should we have performance requirements; how should we incent the production; should we get into a competitive pricing. Those sorts of things.

One of the issues with net metering, the original tariff, which started out as a 10 kilowatt maximum size of project, gave, with the full bundled rate, credit in a sense a pretty strong incentive in addition to the very other exemptions.

And as part of that whole legislative package there was a cap, as you know. Right now it's a half a percent of the utility demand.

Were we to, let's say, increase this tenfold or a hundredfold, we might not want to price all generation that's exported into the grid as a resource at bundled retail rates.

So where there's a little bit of a -- and unfortunately maybe it's not a hard black-and-white boundary for us, between what is where we leave off employee customer conservation and load reduction and load management to a resource.

PRESIDING MEMBER GEESMAN: Yeah, I think I can see that. On the other hand, the state government tends to be focused on generation. I don't think that the level of involvement with how the distribution system is run is nearly as great in state government.

And certainly the business community and your industry and others have made quite clear over the years that we are a generation-limited state. In fact, our recent Integrated Energy Policy Report suggested or concluded that that is very much the case in southern California.

So, I think that the line of consistency that I would draw around the previous expressions of legislative policy embodied in statute, and the policies of this Commission and again I believe at the Public Utilities Commission, has been to encourage generation, you know, subject to environmental and safety limitations.

I understand there are more complexities and some of them are pricing complexities in the distribution system. But I think in going through the decisions that we're called upon to make, I'm having a hard time thinking why we shouldn't be motivated by that concern for trying to increase generation.

And I acknowledge there's some rate setting and tariff administering complexity to that. But as a simplification isn't that a desirable objective or desirable priority?

MR. TORRIBIO: It would seem to me to be a key priority; and it may be that the way to reconcile the desire to further generation in any way we can is going to be in conjunction with the cost/benefit type studies which we're expecting to come out of the PUC's proceeding.

PRESIDING MEMBER GEESMAN: Yeah, and I don't want to prejudge that at all. I recognize the complexity there. And am looking forward to the results. But they're a ways off.

COMMISSIONER BOYD: I want to add my "me, too" to that. I turned my mike on a moment ago, but Commissioner Geesman said exactly what I was thinking. Because he and I, we sit up here in other contexts listening to forecasts of a generation-starved state in the not-too-distant future.

And it just seems, in the context of all this discussion we've been having, if there is generation available and I agree with all the cost, beneficial cost effectiveness tariff provisions and what-have-you, nonetheless it's hard to explain to the unwashed general public in one hand that we have generation we're not using, and yet we need to put more iron on the ground, as people love to say.

So, this is something we are anxious to reconcile. And I think most reasonable people would want to maximize that which we have before making any other investment.

So, excellent dialogue; good point. And a dilemma for all of us.

MS. SHERIFF: I just have a --

PRESIDING MEMBER GEESMAN: You have to come to a microphone; you also have to tell us your name and who you represent so the court reporter will catch you in the transcript.

COMMISSIONER BOYD: So if you're willing to do all that, then you can --

(Laughter.)

MS. SHERIFF: Certainly. And I'll be on the next panel, as well. My name is Nora Sheriff. I'm here on behalf of the Cogeneration Association of California and the Energy Producers and Users

Coalition.

And I just wanted to -- I brought this up on Tuesday at the public meeting -- and I just wanted to draw your attention again to section 372 of the Public Utilities Code which provides a state policy for encouraging cogeneration.

So there's not just the legislative policy encouraging the net energy metering projects, it's also for cogeneration there, as well.

Thank you.

PRESIDING MEMBER GEESMAN: Okay, thank you.

Scott, do we have anything else before our lunch break?

MR. TOMASHEFSKY: No, I think that's it. I just, in closing that discussion I just also wanted to bring us back to when we think about these combined technologies, it's not simply just a matter of having these multiple configurations within a project, but sometimes they also represent repowers, if you will, for lack of a better term.

And so the issue of how do you deal with the review of that application for interconnection has impacted some of the projects and costs; it's something we need to consider, as well.

PRESIDING MEMBER GEESMAN: Sure.

MR. TOMASHEFSKY: We haven't really addressed that too much, but just wanted to leave those in passing.

PRESIDING MEMBER GEESMAN: that's a good point.

MR. BLAIR: And one additional comment. In the City of San Diego we do have planned several, fairly large, distributed generation components. And you also have to look at the other metering rules where you can only have one meter per site, because they play into the cost effectiveness, too, and cause the other problems with the multiple tariffs on one meter.

So, we may have one where we'll be looking for full export of one of the systems at the site, and on the other will be offsetting peak load during the day, but could be under a net metering tariff, also.

PRESIDING MEMBER GEESMAN: Um-hum. Okay, why don't we take our lunch break and reconvene at 1:15.

(Whereupon, at 12:15 p.m,. the hearing was adjourned, to reconvene at 1:15 p.m.)

AFTERNOON SESSION

1:22 p.m.

MR. TOMASHEFSKY: Welcome back. The last panel of the day is going to focus on net gen output metering issues. And I can tell you this has, by far, been the most contentious issue that we've dealt with in quite some time.

Just as general background, and then we'll let all that want to make their pitch go ahead and do that, as general background the net gen output metering section is part of a telemetry section of Rule 21. And there have been some issues about -- the fundamental issue is whether or not the utilities require a net gen output meter.

Again, this really has less to do with the technical interconnection aspect of the problem, but there are revenue issues that bring it right into the forefront of this discussion and interconnection issues, just in terms of when you put the meters on.

What you're probably going to hear is you're going to hear a discussion that goes fairly wide-ranging. It has to deal with the need, in essence, to even have a net generation output meter. And there's some aspects within the working group paper that we seem to agree that it's required. And I'm not going to repeat those there, but they'll come out in the discussion.

There's a number of other areas where it's definitely not a consensus issue. In fact, we have been at an impasse, as a working group, for quite some time now. And the way we've dealt with it in the working group, in the tariffs, is there's a series of permanent metering assumptions that are supposed to be adopted by the PUC. First it was by 2002; next was by the end of this year. And now it's 2005.

So each year when it comes up to the deadline we end up extending the date another year. So we're really looking for some guidance here, and as we can move forward.

So, what we'll do here is we'll start off with a discussion undertaken by EPUC and CAC, which Nora will frame their perspective to the table. And then we'll follow by a number of utilities' perspectives. And we'll just continue to go from there and let the discussion go.

Again, this is definitely one that

requires probably a little bit more guidance from your side of the table.

With that, I'll turn it over to Nora. And I'll get the presentation going here.

MS. SHERIFF: Thank you, Scott. And thank you, both Commissioners Boyd and Geesman, for your continued attention today.

As Scott mentioned this morning and just reiterated again, the metering issues that the Rule 21 working group has been dealing with have been contentious. And have been debated over the past two years.

CAC and EPUC have been participating in the working group and in the debate. We believe, however, that we've come up with a balanced and flexible solution to the question of should net generation output metering be required. And when should it be required.

And that solution is on the next slide. Thank you. Where a customer receives a ratepayer-funded incentive such as the self generation incentive program payment, or the CEC emerging renewables payment, it may be appropriate to have a meter.

Where they receive an exemption from

standby charges due to their status as a distributed energy resource, again, net generation output metering may be appropriate.

Again, if they get gas service under the cogeneration gas rate, but don't have a gas meter there to measure that usage, and they need the electric meter to estimate the gas usage, then the electric meter may be appropriate.

Or if the customers elects to have one, choosing to have that meter there, that's their right. So that is the solution we propose.

In terms of -- next slide, please -- in terms of arguments about it's necessary for tariff administration, the CPUC has affirmed the use of estimation for billing the non-bypass-able charges for a departing load customer. This was most recent in the customer generation departing load cost responsibility surcharge which they addressed last summer.

So, PG&E's appendix A, -- which, thank you, again, PG&E; it was very helpful having that matrix there -- shows that for standby charges there is no need for metered data.

And then in terms of the determination of your cogeneration status for tariff exemptions, for example, the CTC, this is actually an annual calculation that's detailed in Public Utilities Code 218.5. And there's no real need for monthly metered data to perform that annual calculation of the cogeneration's efficiency.

In terms of the utility system operation and planning, there's no need for net generation metering. The utility system is impacted by the flow of electrons onto and off of their grid, over the point of common coupling.

And that point of common coupling meter gives them that information and tells them what's going onto their system and what's coming off of their system.

It also could be impacted by the size of the generator, what's the installed capacity. And that information is reported to the utility as an element of their interconnection.

So they have the two pieces of information that they need from the point of common coupling, and also the interconnection process.

And net generation metering is costly. If you have 13.8 kV installation, it can range up to $30,000 for one generator. And you can occasionally have a customer which has multiple generators that size. And that's a significant cost. It's also intrusive. And this is something that we've emphasized in our comments, customer concerns over the confidentiality of their operations data and their information.

And the PUC has recognized this, in the early decisions in the early '90s, they said that they saw where the disclosure of that operational data could cause competitive harm. So it's a valid concern on our part.

And we feel that there are reasonable alternatives that the PUC has adopted and approved of, and they're available in the utility tariffs. And that any solution in terms of looking at this question has to be balanced and flexible in order to, as you say, we're in a generation-focused state; we want to permit distributed generation and add generation.

The other two issues that are covered in the metering umbrella, who should own the meter and what quality meter should be used, our position is similar. You need to have a balanced and flexible requirement there, with the eye towards promotion of distributed generation.

And cost considerations really need to be taken into account, particularly in terms of the quality of the meter to be used. Revenue-grade quality meters are significantly more expensive than others.

So, with that said, thank you again for your attention, and we look forward to this afternoon's dialogue.

MR. TOMASHEFSKY: Dylan, since you have a one-pager, why don't we go with you, and then we'll switch over to Dan after you're done.

MR. SAVIDGE: Thank you, Scott. I'd like to start off by saying first off, PG&E does not require net generation output on all DG. In fact, for most of the projects out there, a majority of which are net generation, I mean net energy metering projects, we do not require net generation output meter.

In cases where we do I have tried to illustrate that in the attachment A in the CEC report in order to lend clarity regarding when and why we do require a net gen output meter.

Just to recap, kind of rephrase the appendix, we currently require net gen output metering for standby tariff exemption qualification under PUCode section 353.15, which is basically an annual operating efficiency standard. Which we need three parameters, and one of which is the electric production of the generator.

The discount gas transportation tariff qualification. And that has several components, and Nora touched on one, which is the efficiency standard for cogenerators. But I think, you know, there are a couple of instances in which we've had discussions over, and I'm sure we will have more, where -- and which are outlined in appendix A, where we feel we do need a net gen output meter. I won't get into those details now primarily because I don't have the attachment A in front of me.

We also require net get output meter for the self gen incentive program. And that meter, itself, is funded by the program, itself; and carries with it the requirement for quite a bit more data that we're typically looking for in a net gen output meter.

And then for larger generators requiring telemetering.

I'd like to just point out that

typically the net generation output meter is not a big, elaborate, fancy meter, load-profile type meter. It's normally simply just a totalizing kilowatt hour meter. And typically for smaller DG installations it looks like a house meter on a house panel.

Now CAC has pointed out that some installations these costs can get up to $30,000 and we don't disagree with that. Particularly where you have higher voltage installations.

We've provided our viewpoint on what that cost might be, and we came in with a figure closer to $15,000. But nevertheless, we are sensitive to that, it can be a costly proposition.

So therefore we want to assure everyone that we do require the meter for very good reasons, and typically for tariff administration, for compliance and billing purposes.

For most DGs that do require net generation output meter you'll see in this appendix A that PG&E does require PG&E ownership of that. And I provide some comments where we feel that is important.

Addressing the possibility of using alternative methods of either establishing the data that would normally be gotten by net generation output meter, we feel the net generation output meter is the most effective and efficient means of establishing charges, for example, in compliance for customers receiving either tariff benefits or have an obligation for ongoing -- and thus have an obligation for ongoing efficiency requirements. But also for billing purposes for departed load non-bypass-able charges.

It's been proposed that alternate methods, in fact supported by a recent Commission resolution on PG&E in its advice letter seeking the use of metering, and implementation of the CRS cost responsibility charges for departed load that the Commission supported the use of an existing methodology found in PG&E's preliminary statement BB, which uses basically an estimate method as a default.

It is always the customer's option to use a meter if they feel that estimate method does not accurately represent the charge.

PG&E does have a concern with having that as the default method, because that can often lead to disputes and misunderstandings if those charges are not clearly explained upfront and the customer has a, you know, perception of what that charge might be.

We feel an estimate method is, at best, an estimate. It is not, you know, it can vary widely due to the DG's performance. Again, departed load is based on the DG performance. Some months the DG does not operate at all. And using the estimate method found in the preliminary statement would then grossly overstate the departed load charge.

So therefore PG&E proposes to continue the requirement for net generation output meter as stated above and in appendix A. That's PG&E's position of preference.

However, we wish to continue dialogue with the interested parties, and have a commitment to work with some mutually agreeable solution.

PRESIDING MEMBER GEESMAN: But wouldn't the logic of your position suggest not simply the continuing of existing net generation metering, but in fact expansion of it and the replacement of these estimate methodologies wherever possible?

MR. SAVIDGE: Correct. We feel that as it currently stands we've had experience with the current accounts for which we bill using the estimate method has increased administrative burden through customer complaints and dispute. And we view the solution would be to install a meter --

PRESIDING MEMBER GEESMAN: Okay.

MR. SAVIDGE: -- to really assess the charges.

PRESIDING MEMBER GEESMAN: I thought that's what you were saying. I just wanted to clarify.

Who's next, Scott?

MR. TOMASHEFSKY: Dan.

MR. TUNNICLIFF: Thanks, Scott; thanks, Commissioners. And I wanted to thank Scott, and we all worked through this process. We may reference this as one of the contentious topics. I might recharacterize it as lively.

(Laughter.)

MR. TUNNICLIFF: Scott, through his leadership, has really done a good job herding this group of cats. We all still can look at each other and spend time together at lunch, if necessary, or when we choose to. So even though it's been lively discussions and differences of opinion, I think that we're working well towards resolution.

One thing I think I'd like to point out briefly is we generally agree with what's been in the report, what's in the Rule 21 working group report. There have been some recommended improvements suggested in some of the comments; but, generally if you look at the metering section for the vast majority of the projects that have been installed in our service territory, I can only speak for SCE for 2003 and probably this year, most of them are taking advantage of some sort of an incentive. Either a standby exemption or a self gen incentive program.

Most of these projects I think many of the positions represented here would believe that net gen output metering would go along with those installations because they're getting publicly funded or ratepayer funded subsidies, either in the form of standby exemptions, self gen incentive program, et cetera.

We do have a desire of becoming better at using data from net gen output meters for operation and planning. We recognize that the fact that our tariffs do allow for estimation.

And one thing that was pointed out, and Nora correctly pointed out, in the Commission decision on departing load, that estimation is allowed. But what we've neglected to talk about was the -- I think the reference is utility tariff provisions for measuring and estimating shall be used for billing.

All of those, at least with SCE's preliminary statement, starts off with requiring billing and metering of net gen output. If reliably metered data is not available, estimation can be used.

Dylan pointed out a couple of issues that they've had with complaints from the estimations. We had similar complaints and have come to resolution on those. But since about 2002 SCE has been requiring net get output meters. I believe San Diego has generally required them every since we've been interconnecting. And PG&E has been requiring them as of late as well.

What's contained in the report and what we've been talking about today focus on our current state and dealing with our current tariff structures, et cetera. Very little, I think, is known about what's going to happen under the cost/

benefit piece in the DG OIR, the companion proceeding to this.

We don't know what costs and benefits are going to be assigned to DG and how we're going to be able to quantify that to make sure our ratepayers, if we're funding these programs, are actually receiving the benefit. So we don't know, one, what's going to happen out of that proceeding.

Other metering issues could come up out of the advanced metering investigation that's currently underway throughout the state. If we're looking more and more at treating our customers as resources, why would we not want to have real data from some of these other resources that are looking -- that the state's looking at as providing a benefit to the utility system.

And most recently in October the resource adequacy requirement decision acknowledges that in our long-term procurement plans the utilities use and forecast DG as a load reducer. We take the estimates on kilowatt hours produced and reduce our purchases accordingly.

What the conclusion of law 11 basically said in that decision was load forecast reductions reflecting customer's side of the meter DG impacts should reflect the output the facilities are actually producing. Not necessarily these nameplated estimates and how we currently estimate, if that's the track that we go down.

Those are a couple of the points that I wanted to make as far as what we don't know.

And then the next question becomes more of a question or a comment about what are the longer term needs of the California Energy Commission and the state for forecasting under the Senate Bill 1389, which I believe the Integrated Energy Policy Report came out of. What are the data needs that the policymakers need to forecast for our future resources. Only the policymakers, you Commissioners, are the ones that are going to be able to tell us what level of detail we need from all of the different resources we have in the state.

And with that, that's about all I wanted to say about this topic.

PRESIDING MEMBER GEESMAN: Now, you don't get this net generation metered data from your QFs, do you?

MR. TUNNICLIFF: Not that I'm aware of.

PRESIDING MEMBER GEESMAN: It's not a requirement on QFs?

MR. TUNNICLIFF: Right.

PRESIDING MEMBER GEESMAN: And in your service territory what would you say that the installed capacity of your nonQF DG is compared to the QFs?

MR. TUNNICLIFF: Well, I think what's different about QFs versus the DG, DG-serving customer side of the meter loads, QFs are generally under the firm contract commitments. And it's too cost prohibitive for them not to produce and supply power under contract.

I think that the last estimate I think Scott had on the graph about 240 megawatts I think is the -- 220 to 240 megawatts of DG has been installed since about 2001. I think a third of our power procurement comes from QFs, for our whole power portfolio, it's about a third. So it's quite a scale of magnitude different.

PRESIDING MEMBER GEESMAN: So am I wrong to try and establish a context in terms of these information needs, either on the part of your company or this Commission? The QFs massively overwhelm the numbers on the DG side. You've been able to get by without net metered data from the QFs.

From an informational standpoint, isn't it going to be a pretty long time before the DG numbers are up to the magnitude of the QFs?

MR. TUNNICLIFF: I think it's a different issue with the QFs being under firm contract, it's something that we rely on. It's a firm commitment.

We can't necessarily rely on DG, customer side DG --

PRESIDING MEMBER GEESMAN: Okay, so that's the distinction that you draw?

MR. TUNNICLIFF: Right.

PRESIDING MEMBER GEESMAN: Who's next, Scott?

MR. TOMASHEFSKY: Mike.

MR. IAMMARINO: I just have a short comment. It is true that San Diego has, since the inception of the new Rule 21 in January of 2001, has pretty much interpreted the rule to require net generation output metering from DG units.

Net metering aside, we have not -- that's a separate issue.

And by doing so, during our meetings,

the 63 meetings we've had, I've been able to sit back and smile at my sister utilities because we have not had anywhere near the problems they have trying to resolve their bills. And I think it's worked very well for us.

One thing I always thought was interesting was the DG community have always brought up in section F of Rule 21 that, you know, it should only be required if they're net generated to the extent that a less intrusive and a more cost effective options are providing the necessary -- output are not available.

And it seems to me that I interpret, or what I see is that that's being interpreted, well, it's not less expensive to -- DG, but I look at it as from the utility perspective and the utility's ratepayers, every time you interrupt this automatic system of millions of customers to do all this automatic billing, it costs money. And that money has to go somewhere.

And we have the experience, we put it in the paper, of just one customer. And that's because it was just before the Rule 21 went into service in 2001, we didn't have a net generation output metering.

And so the data that we've gotten from that one relatively small customer costs us a lot of administrative time to do. One, the data is not timely when we ask for it. Secondly, the data is not verifiable. We just get it from them; we trust them that that's correct. And the third thing is we have to manipulate it to get it into a format that will fit in our billing system. So all that takes time.

And one other interesting phenomena that came up just from this one was that I'm sure most companies around here now, because of what happened at Enron and the Sorbanes Oxley, took a look at this and they said, what, you're paying this person and you don't have this metered data. You're getting it from the customer and trusting them. And we said yes.

So I think that that's another issue that's kind of more subtle, is that, you know, Sorbane Oxley, from where we're going in our company, is that they really expect a good paper trail and good documentation of how you're conducting your business. And I think that's something that is probably going to be more prevalent as time goes on.

MR. ROSS: With respect to what we're recommending, we're not recommending that they pay anybody without having metered data. What we're talking about is a less intrusive way for them to deal with administration of tariffs or to get the planning data that they may need to operate their system efficiently.

And we think there are alternatives. And what we're saying is one size doesn't fit all. And we recognize that there are situations where net generation metering may be necessary, and it could be that the customer agrees with that.

There are other situations where the customer doesn't want his data compiled in a way that the utility may be wanting to compile it. And would prefer to live with an estimate. Or to provide data in another manner that's still acceptable and doesn't cause huge administrative burdens, but doesn't allow the utility to have the detail with which you're putting a generation meter on.

So that's our position, is try to be fair and flexible on both sides, and work out something that encourages distributed generation, and at the same time provides the utility with the information that they need to operate their system.

MR. TOMASHEFSKY: Before we continue, I just want to let Mark Moser have his opportunity to speak. And then we can just freewheel it from that point on.

MR. MOSER: Good afternoon; I'm sorry I was a little late getting here; got in late from New York, but --

The only comments I have are, you know, directly relating to the dairy net metering. And as far as net generation output metering, as far as we can tell, it's not required by the PUC for these little QFs.

We believe that we were exempted under AB-2228, yet the utilities have imposed net generation output metering over our objections, and because they can very simply by saying, if you want to get hooked up you're going to put the meter in or we're walking away. That's a very simple one-sided conversation. So you do it.

PG&E's done it. SCE hasn't done it yet, but after six months of operation they're still out messing around at the farm. So, you know, it may show up. We don't know.

I have a few comments that I missed making earlier, but anyway, one thing I can say from our experience down in Lodi with PG&E at the net generation output metering, if this is an example of simplified billing, this is a one-month bill for a dairy farm.

And this is -- they have three separate meters that measure the outgoing current. And it appears that the dairy farm is being billed for them all. So how did that help? Used to have a $16,000 bill and it's now almost double, even though he's running 150 kW around the clock. I don't know.

The point is we don't think it was required; it's been imposed; you know, where do we go from here?

PRESIDING MEMBER GEESMAN: Anybody have anything more that they would care to say? We've got a fairly extensive written record on this, and it appears that everybody's got their own positions.

Yes, sir?

MR. TORRIBIO: Thank you, Commissioner. Just a reference back to some comments you made a few minutes ago about the context, or trying to frame the context --

PRESIDING MEMBER GEESMAN: Yes.

MR. TORRIBIO: -- in which metering might be required. I'm reminded of the beginning stages of the Rule 21 development with the working group. And one of the dilemmas that we worked through was do we make requirements that are so perfect and all-encompassing and protective of the grid and the rest of the customers that the next generator to go on there will basically bear the burden of reinforcing the grid for all time to come.

Or do we rather relax somewhat, or make simplified requirements and see how it goes as we get more penetration.

And one of the main premises of the Rule 21 working group, and I think it's reflected in the rule, notwithstanding the frustration some people have with it, as it is, was that even though DG may, and might very well have increased penetration on the grid, serve more and more of the customer load base with time to come, right now we would plan for a reasonably current level of penetration and then revisit on an ongoing basis.

One of the issues was perhaps we'll get to a point where there's a lot more flow in the circuits back up toward what used to be the central generation source.

And I would just say getting it down to the topic of metering, that as the grid is evolving and transitioning, and as our use of it collectively changes, this would not, to our point of view, Edison's way of thinking, be a time to start turning off sources of intelligence or reducing our database just because things have gone all right thus far.

With the 200 megawatts or so of DG penetration in our area, I'm not sure -- that is very low, fairly small proportion of our total customer load. I'm reminded of one of the presentations made at, I believe, the Cader conference, by someone who was -- last January -- who was talking about Denmark, which supposedly has about 60 percent of the entire country's customer load served by various kinds of disbursed generation. Some of that may be large QFs, I'm not sure.

But one of the points made was that the types of outages and the types of operational situations are new, not insurmountable, but require different approaches and different kinds of analysis.

So I just wanted to make the point that as we grow and as we evolve in the use of the grid, this would not necessarily be the best time to shut off sources of data about the generation and go on estimates and go on past practice.

PRESIDING MEMBER GEESMAN: Well, I guess the concern that I'd have there is trying to balance a variety of competing priorities. The one that I think the Legislature and this Commission and the Public Utilities Commission seems to have been the loudest on over the longest period of time has been to try and promote these distributed generation technologies.

So to that I would attach some virtue if they represent an expanding contribution to our overall generation needs.

Commissioner Boyd and I both made the remark before lunch that we appear to be generation starved, and as a consequence we have an interest in promoting more generation rather than less.

I think the concern with expanding

information gathering approaches is when that expansion becomes a barrier to achieving either of those two other priorities. I don't think I disagree with you as it relates to the increased complexity of operating a distribution grid that we're likely to see in the future as we diversify our various sources of supply. I don't think I disagree with you at all.

I'm not certain, and I hope to gain more knowledge as Commissioner Boyd and I deliberate on this, and we review these materials still another time, I'm not certain where I would assign the cost responsibility for that improved information gathering.

And it may be different answering it today than two or three or ten years from now. Depending on levels of penetration.

But it strikes me that to the extent that there are greater administrative difficulties attached to billing on the basis of estimates, then those are greater difficulties and greater costs that the Legislature and this Commission and the Public Utilities Commission should ultimately say, well, that's part of the cost of our other policies. We want the ratepayers to pick up those costs because we think that they are justified by our interest in expanding and diversifying generation and encouraging these particular technologies.

I think there's a pretty bright line, though, as it relates to properly policing and administering the various incentive programs. I think there's a very clear desire to avoid having those ratepayer-provided subsidies abused or gamed.

So I can see a different interest there in terms of trying to precisely monitor net generation output metering when public subsidy funds may be at stake.

As it relates to customer friction or differences or what-have-you, I think that's a problem. You know, to some extent though, it's a problem that is probably more severe to the DG customer who may have brought this onto himself or herself by insisting on proceeding on the basis of estimated data, than the utility, which should be able to get all of its costs recovered from its other ratepayers.

MR. TORRIBIO: That's the issue of the cost to the customer, or the customer generator.

It sort of brings up the discussion we had earlier about getting a better handle, a much better handle on the costs the utilities incur.

In review, when we talk about the cost to the customer in terms of its impact or perhaps even its role in discouraging generation, that's an area where we have very little information about, you know, what percentage of the capital cost of the DG project does the metering represent.

We might usefully get benefit from more hard data rather than anecdotal.

PRESIDING MEMBER GEESMAN: Yeah, and I think we all fall prey to the policy-by-anecdote approach. And I want to resist that wherever we can.

MR. TORRIBIO: Thank you.

MR. TOMASHEFSKY: There's two corollary issues that we haven't really focused on, but you have to make the fundamental assumption that given the -- if you assume that estimated data is not okay, and you do need some sort of data, there's two questions.

One, does the data have to come from a utility-grade meter. And if it doesn't come from a utility-grade meter, what type of standards should be imposed on that meter that's providing that information.

We've had a significant amount of discussion on that issue, as well. That's been less of an EPUC issue, more of a Real Energy issue. But they're not so concerned about the estimation aspect, but they have argued in many respects that there's been instances where the quality of the information that they're providing to the utility has actually served as a backstop when the utility meter hasn't worked.

So, thinking along those lines, there's some areas that even if you go the next step to say estimation is okay or not, you still have to deal with the data quality issues.

PRESIDING MEMBER GEESMAN: Sure.

MR. TOMASHEFSKY: With the Rule 22, direct access rules that were established, there's metered data management rules that were put in place, some standards. And those are generally acceptable, at least in terms of what specs are needed for the utility to use that information correctly.

But where we did not go is how does that apply to the nonutility-grade meter. And I don't know if anybody has any comments on the panel with respect to that issue. But that might be worth talking about for a few minutes.

MR. ROSS: Most of the generators have meters. It's not a case that there's no data. But very few of the ones that I represent have revenue quality meters.

So the data that would be used, let's say for load forecasting on an annual basis, or information to demonstrate that you meet your qualifying facility status, that information is available to be provided to the utilities in aggregate form, on an annual basis, or in some form. Maybe supplied to you and then you aggregate the numbers and then you provide it to the utilities for confidentiality concerns.

So a lot of the information that we've talked about today really is not, I don't think, necessary from a revenue quality standpoint. It's data, but what it's used for, the other data, it's not revenue quality, either.

With respect to what Dylan was talking about, where you are using an electric meter to estimate what the gas usage is, you may or may not need a revenue quality meter. It could be that the meter that's on there, because you're still making an estimate because you're using a heat rate that's basically a heat rate that's for manufacturer's data. That's being adjusted for elevation and the other aspects that affect the generator.

So, some of this is not real clear and bright line on whether a revenue quality meter is needed, even when it's used for billing purposes, but I mean Dylan may have a different take on that.

MR. SAVIDGE: If I may? I think there's another issue on using the electric generator meter for gas billing purposes is timeliness, retrieval of the data. So that really points to, as I've suggested in attachment A, is the utility ownership, which then would be utility-quality meter.

Because we've had issues in the past of getting access to that data on a timely basis, and we have a requirement to get bills out on a timely basis, as well. Hopefully thinner than the one that was presented by Mark here.

MR. ROSS: And I would agree that that's

a valid concern. And if we're really talking about totalizing metering and the customer agrees that they want to use electric metering as opposed to putting in the gas meter, there's obviously probably an economic or physical concern there, then that may be an appropriate use.

Again, what we're proposing is something that gives you the flexibility to determine what the utilities requirements are, and also meet the customers concern about confidentiality and intrusiveness.

MS. SHERIFF: And then in terms of the self generation incentive payments, I'm not as familiar as Dan and Mike and Dylan probably are with the self generation incentive handbook requirements, but looking back at the initial PUC decisions on that, they discussed a simple relay switch rather than a revenue-quality meter to determine that.

And recall that that meter, the self generation incentive meter is paid for by the ratepayer funds; it's subsidized by the ratepayer.

So, one would think, well, let's make that ratepayer money go as far as you can, and not get the most expensive thing out there with all the bells and whistles. Just determine what do we really need, and just get that.

MR. TUNNICLIFF: Yeah, a point we've made on the costs associated with it, and some of the working group workshops we've had leading up to this is, you know, put it onto, or at least have the developers and the manufacturers of some of the units. They come oftentimes, or I've been hearing they come oftentimes with packaged meters or what-have-you.

Maybe some additional work can be done on the development side about what metering requirements are more universal, if they are out there. And do that upfront.

It seems that the manufacturer could do a great service to their customers that they're selling the units to of making sure that they meet all the data needs that they will have to deal with when they go to interconnect these facilities.

Again, there's additional work that seems to be necessary to deal with that. I would imagine that most people putting in DG want to know how it's producing. Let's see how that data could best be utilized for everyone's purpose. I don't know we can say that yet.

PRESIDING MEMBER GEESMAN: Now, is the ownership issue of the meter just a proxy for whether it's a revenue-quality meter or not? Or is that ownership question a separate issue, as well?

MR. TUNNICLIFF: Dylan, do you -- I think from my perspective I'm not in our metering organization; I'm not in our billing organization. If we own it we know that it can be integrated into our system.

PRESIDING MEMBER GEESMAN: Right.

MR. TUNNICLIFF: That, I think, is the biggest issue for us. I don't know if Pat wants to make a comment about that, or Dylan wants to add on that. I think that's the major reason.

MR. SAVIDGE: Yeah, I would agree with that. And there are allowances for customer-owned meters that we prefer to see somehow utility-grade meter for three purposes.

One is initial quality, to make sure the data is accurate. But, also retrieval data. And assurance that there is some mechanism for ongoing maintenance of that meter to assure that high quality data is retrieved from that meter.

PRESIDING MEMBER GEESMAN: Is that a requirement that you currently apply uniformly to all of your customers? Or all of the billing data that you get from meters that your companies own?

MR. SAVIDGE: For PG&E-owned meters, yes. That is a standard we apply. We have standards for --

PRESIDING MEMBER GEESMAN: Do you have any customers that own their own meters and you accept data from customer-owned meters?

MR. SAVIDGE: Yes, that's been an issue. And we have not applied the same sort of standards, nor have even encouraged that in the past. But that's where we've, you know, found a need to take this issue up, because we've had the problem of those three areas with customer-owned meters.

PRESIDING MEMBER GEESMAN: Yeah. Why do you ever allow a customer to own a meter? Or is this a historic practice, or --

MR. SAVIDGE: It's an historic practice, and it was more of an accommodation for the customer. And often cases, as Dan mentioned, a lot of these package units now come -- had even prior to this investigation -- had come with its own meter.

PRESIDING MEMBER GEESMAN: Oh.

MR. SAVIDGE: And there was a certain element of redundancy that we wanted to avoid.

PRESIDING MEMBER GEESMAN: Yeah. How widespread is the practice, do you know? How many customer-owned meters do you have within your system that you rely on for billing data?

MR. SAVIDGE: I couldn't give you the numbers. They're probably relatively small. I'll throw a number out, 10 to 20 percent.

PRESIDING MEMBER GEESMAN: Yeah.

MR. SAVIDGE: Subject to check. But that's --

PRESIDING MEMBER GEESMAN: Do you have a sense as to what it is in your service territory?

MR. TUNNICLIFF: I don't have a sense for that.

PRESIDING MEMBER GEESMAN: What's next, Scott?

MR. TOMASHEFSKY: Well, if we're done with this, I guess we go to public comment. And then we go home.

PRESIDING MEMBER GEESMAN: Is there anybody in the room that wants to share anything with us? Yes, sir.

MR. TOMASHEFSKY: Okay, we're going to try to do this. As we say at the Commission, the lights may go out for a minute, so -- let's see how this goes.

MR. PRABHU: My name is Edan Prabhu with Reflective Energies. I was at the original DG roundtable conference in this room in 1995. And I've watched DG all through that entire period. So my comments today are much more related to the historical, taking a step back kind of perspective, rather than the discussions we've had here today.

This graph, and the only -- oops, I was about to say it's the only one I -- here we go. The bottom line starts in 2001, if I can find it. Okay.

In 2001 the average interconnection time was 375 days. And preceding that was a major report that was given a lot of publicity by the DOE. It was called Making Connections, written by Brent Aldefer, Gary Nokarado and others, that basically substantiated that utilities are taking their time and interconnections take that time.

Last year the average interconnection

time was 70 days. The improvement has really been dramatic. And the single biggest reason for that change is the new Rule 21.

If you think about some of the discussions we've had today, preparallel inspections take a lot of time. Well, it's still happening within those 70 days. If you think that costs are going out of sight, well, the time is one measure of money, and certainly things are happening quicker and more efficiently.

Especially when you consider that many of these delays were not utility delays, but that the developer didn't get things done in the timeframe they wanted.

So what are we looking at today compared to what we looked at four or five years ago? The subjects like should we change the fees, should we improve the dispute resolution, who should play for surplus preparallel inspections. And then some of the brand new topics that have just come out because of new legislation related to net generation -- net energy metering, such as net energy metering for dairies and net energy metering for 1 megawatt.

These are brand new issues on the time

scale that I'm describing. And things have gotten a lot lot better. I appreciate the impatience of somebody with a new issues that have come up.

The working group has been a wonderful means of sounding out issues and coming to resolution on those issues. Unfortunately the working group is very very slow. And some of us don't have the patience for it. And sometimes delays are money, and sometimes delays cause companies to go out of business.

But in the big picture there is a process that's been working well. The Commission has done a really really solid job of driving the Rule 21 working group forward, and we have seen the results.

PRESIDING MEMBER GEESMAN: How did you compile that data?

MR. PRABHU: This is the data from all of the information provided monthly by all of the utilities on the DG application dates, the DG interconnection dates and where the applications stand in the process. It's public data.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you very much. Any comments, questions, additional statements? Mr. Moser.

MR. MOSER: There's some very interesting -- hello, hello --

PRESIDING MEMBER GEESMAN: Green light has to be on.

MR. MOSER: Yeah. Well, I missed the earlier portion of the hearing. But I sure would like to mention that our experience with dairy net metering has been absolutely nothing like that just described by Mr. Prabhu.

We work all over the country putting in dairy digesters and small cogeneration systems. And in general most states and most utilities are accommodating. This is absolutely not the case in California.

The Rule 21 for us is more or less -- I guess I'd say it's immaterial. If you look under the dairy net metering rule you're going to be putting power out to the line so you kick out, is it screen 4 or screen 7, anyway, it's a given that any dairy net metering project -- well, it's not a given, 90 percent sure, you're going to kick out of the process.

And then you go to no process. Then you go to no timeline; you go to there's nothing.

There's no time limits. We got one hooked up down in Lodi at Larry Castelanelli's after about 14 months after we filled out our first application. And, you know, back and forth and back and forth and back and forth and forth and back, and finally there was an article in The San Francisco Chronicle, which was the impetus for PG&E to accommodate us and help us get through this.

And it's because, you know, there's just a -- we don't fit, I guess. Like I say, we're not a 10 kW solar system and we're not less than 25 percent of the dairy load connected on the inside.

You know, we have a system, and we're not unsafe and we're not unknown. I mean, in every other state in the country we're putting out power. And it's not a big deal. The interconnections are known. The processes are known. I mean they make it seem like some great big secret here, there's something special about, you know, you'd think you'd have to have a special toaster for all the requirements you have at PG&E.

PRESIDING MEMBER GEESMAN: So what screen is it that knocks you out of Rule 21?

MR. MOSER: Export. If you're going to put anything on line, you're out. Then you go to supplemental review. And supplemental review is a review with no time limit and no cost limit.

In New York there are actual timelines and actual cost limits. And I heard you say that's not true. There was a meeting at the PG&E offices where they sat there with our client and went, well, should we charge him $5000 or $10,000 or you know. And they just kind of went around the room, oh, seven sounds good. So that's the way it was.

And then they said we're not going to do anything till you give us $7000. Well, that was, you know, for the supplemental review.

PRESIDING MEMBER GEESMAN: So what happens in New York if they can't get it done under the time limit?

MR. MOSER: Well, there's no penalty, but you can complain to the PUC.

PRESIDING MEMBER GEESMAN: How does that work?

MR. MOSER: So far not a big problem. They're pretty good at it. You know, it's not like, you know, with the dairies, they're processing probably right now I'd guess 10 to 12 a year, so it's not a big deal.

PRESIDING MEMBER GEESMAN: Yeah. And what kind of cost limits are there?

MR. MOSER: I think it's 600, 1200. It's, you know, same order of magnitude that we have here, without supplemental stuff.

PRESIDING MEMBER GEESMAN: Right.

MR. MOSER: Because, you know, it's part of the process that they, you know, it's a given that you're going to be hooked up online. And it's not a strange thing, because, you know, this has been done for years.

We have a project near Chico, town of Durham, that's been producing power and PG&E's been buying it for what, 21 years now? It's the only one left in the state where they actually pay for it, and they're still trying to figure out how they can get around that one.

PRESIDING MEMBER GEESMAN: Do you have any experience in Edison or San Diego service territories?

MR. MOSER: Edison was pretty good. There was a hearing at the Senate that was, you know, allowed us -- you know, they've been pretty good to us, but then right after that they changed management and they've been sort of -- for instance, we were online with a dairy digester, been online for about six months.

And then they sent a bill in for $28,000, and they wanted to change the equipment out there for safety because I guess after they approved it as safe once, they decided it wasn't safe. And so they're adding more stuff. And they sent a bill, like I say, without any specifics, in spite of our request. And they told the owner, you know, you either pay the bill now or we don't do a thing.

And the owner was somewhat concerned because he'd been making power for, you know, 120, 130 kW for months, and he's getting zero credit for it. So they came to him with this $28,000 bill and said, pay it or else.

And so, you know, we offered, gee, what we ought to do is get ahold of these guys; get an explanation for this bill. Because some of this stuff we understand, some of it's pretty hazy. And there's a line item for eight to ten thousand dollars that there's just a line item that says money.

We never have received an explanation. The owner did pay the $28,000, and as of this date, I talked to him on the ride up, he is still receiving a bill for $8000 a month in spite of the fact that he is producing more electricity than he is consuming when you look at the two meters.

Because Edison somehow hasn't figured out how to read meters, just like PG&E hasn't figured out how to read meters. And I'm at a loss to explain that, whether it's part of the process, or whether it's just, you know, part of the, you know, -- and these guys, these dairymen, are screaming to all of their other cohorts about how horribly they're being treated by the utilities. And basically it's discouraging other ones.

I mean this has not been easy, this has not been fun. And like I say, there's, you know, other places it goes a whole lot smoother.

Oh, one other thing about Rule 21. Once you kick out of Rule 21 -- oh, in addition to Rule 21 rules, each utility has its own supplemental rules which, once you get -- and we're still not sure how those come in, but you have to, even though Rule 21 is supposed to govern, they can do whatever they want to you once, you know, once you apply. That's where the redundant relays come in.

I think PG&E as of the date, as of my

knowledge, is the only utility in the country that has required that. And I know they're pushing everybody else hard to make sure they do, too.

But we've had a lot of, you know, ground fault relay banks. Well, it was a good idea for PG&E, and so through the Rule 21 process I think they've all agreed that it's something that, you know, probably is necessary, even though outside of California I can only think of one other utility that that is a de rigueur intertie requirement, which, you know, basically means about $10,000 or $12,000.

And that may not sound like much, but, you know, we're dealing with small projects here. Anything -- you know, the average dairy in California has about 1000 cows, and if it made every drop of power it could, it would probably make 140 kW. Most of them can't collect all that manure, so you look at them at, you know, 100, 150.

Two projects that I've discussed that are operating right now, one has 1400 cows and the other one has about 1300. So, you know, they're a little bit larger.

PRESIDING MEMBER GEESMAN: In terms of

the meters that you mentioned, were those revenue-quality meters?

MR. MOSER: Oh, yeah. Yeah, we --

PRESIDING MEMBER GEESMAN: And were they utility-owned or customer-owned meters?

MR. MOSER: Utility owned. We pay -- well, no, -- we pay for them and then, you know, pay more money so that they own them and maintain them.

PRESIDING MEMBER GEESMAN: Right.

MR. MOSER: Whatever the charges are --

PRESIDING MEMBER GEESMAN: Okay.

MR. MOSER: -- called. What we would be most interested in here, and what's going to be most beneficial in the dairy area, is we'd like something that's consistent.

I mean we do not have -- we can't look at a piece of paper and know what we're supposed to do. You know, I don't know if I need this meter; I don't know if I need that relay. And, the whole process is one that is very discouraging. And there are not many people in a half-million dollar project who can afford to spend 14 months trying to work with a utility to get something in and running.

And if we weren't doing this in other states easily, you know, we would be extremely discouraged about continuing to do it in California, in spite of the fact we're from here and we've been here a long time.

Well, like I say, that's what I have to say about, you know, our particular end of the business. And like I say, small cogeneration is just a problem.

I'm going to point this out one last time. It's astonishing, it makes good theater, what it also does, it's another thing to discourage the dairymen. His monthly bills run between $8000 and $16,000. He puts in a generator. Suddenly his bills go to $27,000 to $34,000. And he's at a loss.

So we have to spend more of our time to try and straighten out with the utility that it looks like they're reading all three of their export meters and adding them as a charge to the bill.

And they've, to this point, sort of disagreed, even though if you go out and read the meter numbers and compare them to these pieces of paper, they've charging for meter numbers that are definitely outgoing meters.

And they may say, well, all along, every time we've complained about something, oh, it's just a process; they're learning to develop stuff. And my question to all you guys is, you got 450 megawatts of stuff running and hooked up, how could something like this happen.

That's all I've got to say.

PRESIDING MEMBER GEESMAN: Thank you for your comments. Commissioner Boyd.

COMMISSIONER BOYD: Well, before we lose this audience and, Scott, I don't know whether to thank you or not, --

(Laughter.)

COMMISSIONER BOYD: -- for laying this in our lap. One, I'm impressed with the work, as I said at the beginning of this hearing, that the group has done over the years.

It's been pointed out there's been a lot of progress made. But some really knotty issues were laid in our lap. You got everybody here one more time. Otherwise, you're pushing it off to us to be resolved. And we and the PUC will have to do same.

So, I mean are there any responses, any

comments on the bill that's that size? I mean that's a pretty good piece of theater. Any explanation to me as to why something like that -- I mean there's a lot of illogic going around the room today, as well as a lot of logic.

And a lot of understanding on my part about experimentation and R&D and moving along the path and making some progress. But for Joe and Jane Sixpack out there, I'm sure there's a lot of stuff that they just don't understand, assuming farmers drink beer or Coke or water or whatever was in the sixpack.

MR. BLAIR: Commissioners, Tom Blair again, City of San Diego. Over the 18 months that we've had net generation metering now on various city systems, we had a similar experience in the first couple of months where all the meters appeared to be being read as positive input.

We questioned that. And I've often looked at, there are online computer load profiles that you can access in SDG&E territory. And they don't go negative. So there's no way to reflect if you are generating.

And we have come to various methods that we can look at it now. But after 18 months we now have a method where I actually get a piece of paper each month that tells me how much I'm credited for export. But it's all done manually against the bills.

So they're still working it into their system, and I think it's probably similar in all the utilities. They don't do it automatically.

PRESIDING MEMBER GEESMAN: Stacy.

MS. WALTER: Yeah, I'm Stacy Walter from PG&E. And I just have a couple of comments and maybe some updates.

First of all, I can't explain the bill. But I know that certainly when we get back to the office we'll take a look at it and try and figure out what's in there and work with Mr. Moser and his customer, our customer, to try and figure that out.

So, it could be, I mean there was a couple things that Mr. Moser mentioned. One was the metering on this net metered tariff. It's covered in Public Utilities Code 2027.9, which is the new net metering statute for dairies. And there isn't a net gen output meter required for those customers.

What it is is a meter with two channels.

It's at the point of common coupling. And the tariff, unlike the more familiar PV and wind net metering that's been around for awhile, this requires that all of the power that the dairy takes is measured in one channel. And all of the power that is exported is measured in another channel. And it's measured at the point of common coupling.

And the way that the bill is calculated is that you get a credit based on the generation rate component for what you send out. And you're charged for everything that you take on your rate, except for the generation rate component.

So, it's a different type of net metering. And it's got an extra wrinkle for dairies in that they are able to aggregate other accounts.

So where typically net metering is all done on one meter for the account where the generator is serving that account, dairies are able to identify other accounts. It's a big benefit for dairies actually, so that they can -- because the load serving, the account that actually has the generator may not use all the load, they can use their other eligible dairy accounts and say, you know, these loads are also going to be covered under that program.

And you get billed monthly for your charges except the generation rate component, which gets carried over over a 12-month period, and at the end of the year there's a reconciliation to see, you know. You can apply that to what you actually consumed.

And that's basically how net metering works. And all net metering have an annual reconciliation where you're looking, well, what did they use. You can offset what you used with what you produced. And then it kind of gets zeroed out and you start again.

So, that's just a long explanation for why you might have a bill like that. And there could be some issues that, you know, if we're not reading it properly. If, like you said, if the generation piece is showing up as a positive, you know, we'll have to straighten that out.

But that's kind of the background. And then one other point is, you know, Mr. Moser was correct in terms of fees. There was, last spring, there's an exemption in Rule 21 for net metered customers, now all net metered customers. Last spring it was only for the solar and wind. From paying the 800 application fee, the 600 application fee, and for studies.

And in the spring that was only, you know, Rule 21 only provided for that for the solar and wind customers. And, you know, I'm not sure exactly what the status is of some of the other utilities, it was part of the improvements to the Rule 21 that were being worked out of the Rule 21 working group, to extend that same B waiver to the biogas digester net metered customers, as well.

And for many reasons, you know, those tariffs weren't filed. We went ahead in the summer and filed to get that exemption added to Rule 21. And we asked at that time for the Commission to approve making that retroactive, because there were certain projects that, you know, but for some delays in tariff updating, they would have not been charged those fees.

And I think my understanding is is that, you know, we got the approval for that. The Rule 21's been changed, at least for PG&E. And that, you know, we are -- I'm not sure if we have or haven't actually sent the customer a refund for the amounts that they paid for their supplemental study. And that's subject to confirmation.

Has it gone out, do you know? It's in the process. Yes. So that's in the process. And that wouldn't be just this one project, but any of the dairy biogas digester net metered projects. And also fuel cell projects.

So and that's now in our tariff filed and approved rule. So those are just a couple, you know, updates.

But like I said, you know, we provide all the information. Our solar bills are also a little bit thick because we track over the course of the year for those customers, you know, what have they used, what's the output been. And, you know, we're following a similar model here so that the customer can track, you know, where am I.

But, like I said, it should be easier to go through than that. And we're happy to work on going through it and sorting out, you know, what the issues are.

So, thank you.

COMMISSIONER BOYD: I appreciate what you have to say. I think we'd be kind of curious to know what the outcome is.

I think all the people in this room are

trying real hard, obviously. I will say PG&E is out of bankruptcy. PG&E has shown a lot of generosity in the allocation of funds that they have throughout their organization, et cetera, et cetera.

Distributed generation is here to stay. The policies of the state, the Legislature, this Commission, the PUC are pretty obvious on their face. It's not going away.

So I hope that nobody's trying to frustrate DG any longer. And I'm not saying they are. It's just that this has been an interesting, if not slightly frustrating, day. It reminds me, as a consumer, of dealing with cable companies and satellite companies and my bills at home. But that's, you know, so that's just a Mickey Mouse little thing. I feel for larger corporations that have to have big bills and have to deal with this stuff.

But I just hope we can work this out, because as was said earlier, we're net generation deficient in the not-too-distant future in this state. And it's absolutely silly, in my opinion, to put more iron on the ground and the costs of that when we have these other abilities to squeeze more out of what we have.

And I just hope everybody -- I know you folks are dedicated. And I don't know what you're working under in terms of the messages you get at home, but I think you could feel pretty strongly and take home a message that Commissioner Geesman and I, who I'm confident speak for the entire Commission, you know, want this system, you know, fixed and moving along, and functioning as envisioned in policy and legislation. Sooner rather than later.

And I appreciate the fact that in the last nine, almost ten years, a lot of progress has been made. But, we're not out of the woods. And we still should feel a strong sense of urgency.

So, I look forward to you all continuing to work on this. And you're going to have to look forward to some recommendations that Commissioner Geesman and I will make to our own Commission. It will be conveyed to the PUC. And I just hope we collectively can straighten this out.

But there is a sense of feet to the fire that's going to come out of this discussion and this Commission. So I just share that with you.

Thank you, Mr. Chair.

PRESIDING MEMBER GEESMAN: That's probably a good place to end. Any other comments? Sir.

MR. PATRICK: Good afternoon, Robert Patrick, Valley Air Solutions. Again, on the dairy digester topic I wanted to just make two comments.

There was a very simple diagram shared earlier about the combined systems with dairy digester generation system. Even the simplest dairy is going to be far more complicated than that particular diagram, because there are going to be other meters, as was just mentioned, aggregating out there.

There was discussion on a protection device that we should trigger, and that just wouldn't work well in the dairy case, because there's actually explicitly want the power to go out that way, so it can come back in on that customer's other pumps and other meters someplace else.

One other firsthand example that I have on a preparallel inspection during the second panel that wasn't mentioned. I'm a believer that if something happens once, it might happen twice, it might happen three times. And that's why I share this.

I know of a particular instance where this dairy digester customer was going through the preparallel inspection, going back and forth, trying to resolve problems, multiple trips did, in fact, happen.

On the last trip the inspector signed off on the preparallel inspection. Someone on site was smart enough to say, hmm, are you willing to sign off on that. Let's get a signature right here. So we put it in the shop foreman's office and it's signed off.

Only within a number of business days later to come back in and say, oh, we need a redundant relay. Now, that customer had a little piece of paper that said signed off, so that utility fronted the money and put that redundant relay in.

Did that roll up into that number you just saw? I don't know. But my point is, in summary, in closing, if that information could have been shared on the first return trip or the second return trip, it wouldn't have showed up after the preparallel inspection had been signed off.

And I think this could happen multiple times. And when you look at that cost information that came out on the second panel that maybe you just take it with a grain of salt.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you. Other comments? Anybody on the phone, Scott?

MR. PANORA: I hate to drag this on -- again, I'm Bob Panora from Tecogen. Just a general comment about the Rule 21. I think it's actually a very good document. The framework that it's created is, you know, quite powerful from my point of view to develop projects.

But what really needs to happen and has to be enforced, and it has to be -- what's written in there has to be the way the projects go. And so I think that's very important. Having a dispute resolution process that sort of keeps everybody on their toes is key.

And the other thing that I think is key is that it rolls along month after month, being changed and modified and tweaked. But if you look at who attends the meetings now, it's thinning out. You know, the developers, the manufacturers just aren't coming as much as they used to.

So it is in danger of being not nearly as balanced as it was early on. And it's becoming less so. And at the end of the day we should all be asking ourselves have we made the interconnection process more streamlined, more, you know, spelled out clearer. That's where we're trying to go.

And if it doesn't have a good balance it'll get off the tracks, I think. Maybe not on meeting number 60, maybe meeting 90 or 100 or whatever ones I stop going I feel that, you know, there won't be enough representation by manufacturers and developers.

So I don't know how to address that issue. I just want to make that comment. But, again, I think the Rule 21, as it is, is good. You know, I really am a great believer in it. I just want to see that it gets followed, you know, what's written in there in spirit of what's written in there, is where it goes.

So, that's it. That's it for me. Thank you.

PRESIDING MEMBER GEESMAN: Thank you. Is there anybody on the phone, Scott?

MR. TOMASHEFSKY: Well, I will 'fess up that we have a webcast but no phone, so the answer would be no.

PRESIDING MEMBER GEESMAN: Oh, okay.

MR. TOMASHEFSKY: However, if anyone is listening on the webcast, feel free to email us questions or comments and we can include that in our deliberations.

PRESIDING MEMBER GEESMAN: And do we have a written deadline still outstanding for written comments?

MR. TOMASHEFSKY: No, not for this phase.

PRESIDING MEMBER GEESMAN: Okay.

MR. TOMASHEFSKY: The next set of comments are in response to your Committee's recommendation.

PRESIDING MEMBER GEESMAN: Okay. Well, that will be our next step then.

I want to thank everybody for your attendance and participation today. As well, as Commissioner Boyd mentioned, your participation throughout this process in the prior years.

I think the next step will be our report. And I'm sure that will provoke some comments, as well.

Thanks, again.

We'll be adjourned.

(Whereupon, at 2:40 p.m., the hearing was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Hearing; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said hearing, nor in any way interested in outcome of said hearing.

IN WITNESS WHEREOF, I have hereunto set my hand this 22nd day of December, 2004.